June 5, 1998

Mr. Richard D. Wilson
Acting Assistant Administrator
Office of Air and Radiation (6101)
Environmental Protection Agency
401 M Street, SW
Washington, D.C. 20460

Dear Mr. Wilson:

In April, 1998, the Industrial Combustion Coordinated Rulemaking (ICCR) Federal Advisory Committee (a.k.a. ICCR Coordinating Committee) met to discuss recommendations in a number of areas. The Committee reached closure, as well as consensus, in all areas and is submitting the attached recommendations to the Environmental Protection Agency (EPA) for EPA's consideration in the development of regulations under Sections 112 and 129 of the Clean Air Act.

The ICCR Coordinating Committee was established by the EPA under the Federal Advisory Committee Act (FACA) in September, 1996. The purpose of the Committee is to develop recommendations for consideration by EPA in the development of regulations for the following stationary combustion source categories: combustion turbines; internal combustion engines; industrial-commercial-institutional boilers; process heaters; and non-hazardous waste incinerators (excluding municipal waste combustors and medical waste incinerators). Sections 112 and 129 direct the EPA to develop regulations limiting emissions of hazardous air pollutants (and several criteria air pollutants) from these source categories by November, 2000.

The Coordinating Committee met six times in fiscal year 1997 and, to date, has met three times in fiscal year 1998. Notice of all meetings of the Committee was published in advance in the Federal Register and all meetings were open to the public.

Sincerely,

[Signed By]	[Signed By]
Richard F. Anderson, Ph.D. Stakeholder Co-Chair ICCR Coordinating Committee	Fred L. Porter EPA Co-Chair ICCR Coordinating Committee

cc: Bruce C. Jordan - Director, Emission Standards Division
John S. Seitz - Director, Office of Air Quality Planning and Standards

Attachments

Attachment I - Halogenated Offgas Incineration

Attachment II - Landfill Gas Flares

Attachment III - Scrap Metal Recovery Units

Attachment IV - Boilers Emissions Testing

Attachment V - Combustion Turbines MACT Floor for Existing Sources

Attachment VI - Combustion Turbines Emissions Testing

ATTACHMENT I

INDUSTRIAL COMBUSTION COORDINATED RULEMAKING FEDERAL ADVISORY COMMITTEE

Halogenated Offgas Incineration

Manufacturing processes and equipment which emit halogenated gases and the air pollution control devices which combust those halogenated offgases have been addressed under New Source Performance Standards and existing MACT rules. Additional EPA MACT rule development efforts currently underway will address the need for halogenated offgas combustion control requirements for processes not covered by the existing rules. As a result, the ICCR Coordinating Committee recommends that the ICCR not focus resources on halogenated offgas incineration.

Background

The halogenated offgas category includes incineration of gas streams emitted from manufacturing processes that contain halogenated materials. These streams include process vents and emissions from storage vessels, transfer operations, waste management units, and equipment leaks. Halogenated gases generated by the incineration of solid wastes are not included in the halogenated offgas category, and they will be addressed by the Committee as part of it's section 129 rulemaking recommendations.

Based on the ICCR inventory database and the knowledge of the workgroup, halogenated offgas streams are mostly present in the halogenated solvent cleaning, paper, chemical, and pharmaceutical industries.

Each of these industries is addressed or is scheduled to be addressed by MACT rules. The paper industry cluster rule has been promulgated. The pharmaceutical MACT is expected to be finalized shortly. The final Halogenated Solvent Cleaning MACT addresses parts cleaning operations. The Hazardous Organic NESHAP and the Polymer and Resin MACT rules have addressed halogenated offgas combustion from a large proportion of the chemical and polymer industries. Other chemical and polymer industry processes are being considered in a variety of year 2000 MACT rulemakings.

ATTACHMENT II

INDUSTRIAL COMBUSTION COORDINATED RULEMAKING FEDERAL ADVISORY COMMITTEE

Landfill Gas Flares

Landfill gas is regulated under the New Source Performance Standards and Emission Guidelines (NSPS/EG) for municipal solid waste (MSW) landfills. Additional regulation of landfill gas is being addressed under the recently initiated EPA MACT Rulemaking for MSW landfills. The ICCR Coordinating Committee, therefore, recommends that the ICCR not focus further resources on landfill gas flares.

Background

During the anaerobic degradation of materials in MSW landfills, gases are generated that may be released to the atmosphere. To mitigate these emissions, the EPA requires that systems be installed and operated to collect and treat the gas. A gas flare is commonly employed as a primary control device or as a backup to power generating units.

The combustion of landfill gas provides substantial environmental benefits because the methane is converted to carbon dioxide. As a "greenhouse" gas, methane's potency on a weight basis is over twenty fold that of carbon dioxide. This was recognized in the President's *Climate Change Action Plan* which specifically states that landfill gas be collected and destroyed.

Landfill gas and gas flares are addressed under various Clean Air Act sections including:

Section 129 Requirements. Section 129 applies to "solid waste combustion." Because solid waste is defined to exclude gases (except gases which are in containers), Section 129 does not apply to landfill gas flares.

Section 112 Requirements. MSW landfills are listed as a Section 112 category, but landfill gas flares are not. Landfill gas flares are identified as a control device within existing NSPS/EG for HAP emissions, and these standards and guidelines include performance criteria for these flares.

Section 111 Requirements. Performance criteria for landfill gas flares are included in the NSPS/EG regulations for MSW landfills.

The Committee believes that the ICCR should not focus any resources on landfill gas flares.

ATTACHMENT III

INDUSTRIAL COMBUSTION COORDINATED RULEMAKING FEDERAL ADVISORY COMMITTEE

Scrap Metal Recovery Units

Scrap metal recovery units are specifically excluded from the definition of solid waste incineration unit in Section 129. Certain types of scrap metal recovery units (Pb and Al) are already being addressed under Section 112 MACT rulemakings. In addition, at least in the cases of copper wire and steel, mechanical processes such as chopping, shredding, and classifying are replacing combustion as the recovery technique. The ICCR Coordinating Committee, therefore, recommends that all scrap metal recovery units not receive further consideration in the ICCR process.

However, the Committee has the following three questions for EPA:

> What is the status of EPA plans to regulate electric arc furnaces melting scrap iron and steel ?

> Will precious metals (e.g., silver recovery) be handled by another MACT standard ?

> Where does EPA plan to regulate secondary copper facilities burning wire ?

Background

The COmmittee has identified a number of different types of scrap metal recovery units in the ICCR database. The metals recovered in the listed units include copper, lead, aluminum, ferrous, and precious metals. Some smelt or sweat out the metal from the unwanted combustible or noncombustible matrix; others simply burn off the combustible insulation or coatings. In many cases, these units are area sources of HAP emissions.

The secondary environmental benefits of scrap metal recovery are consistent with EPA’s statements in support of recycling and overall environmental benefits. For example, the EPA has identified many benefits when scrap iron and steel are used instead of virgin materials (iron ore and coal) to make new steel, including: total air pollution emissions drop 86%, water effluent discharges fall 76%, water use is reduced 40%, and mining wastes are reduced by 97%. Similarly, using recycled aluminum or copper scrap rather than virgin ore reduces energy use by 95% and 85% respectively. Clearly regulation of these types of sources should take a life-cycle view rather than focus solely on the combustion that may be involved.

The following addresses how scrap metal recovery units are considered under the various regulations.

Applicability of Section 129 Requirements

Section 129 of the Act applies to “solid waste combustion.” The Committee believes that the combustible materials that are fed to scrap metal recovery units may be classified as solid wastes. However, Section 129(g)(1) contains a number of explicit exclusions from the definition of “Solid Waste Incineration Unit” and reads, in part, “... *The term ‘solid waste incineration unit’ does not include (A) materials recovery facilities (including primary or secondary smelters) which combust waste for the primary purpose of recovering metals***,** (B) ... ‘ [italics added] 42 U.S.C.A. §7429(g)(1). Therefore, scrap metal recovery units are not solid waste incineration units, and Section 129 does not apply.

Applicability of Section 112 Requirements

As mentioned above, secondary lead and secondary aluminum production MACT standards have been or are being promulgated. Secondary lead smelters produce lead metal from scrap and provide the primary means for recycling lead-acid automotive batteries. The secondary lead smelter MACT standard was promulgated on May 31, 1994, and covers area as well as major sources of HAPs. The secondary aluminum production MACT standard is expected to be promulgated in 1998. It will cover major HAP sources only.

According to the Section 112(c)(6) emission inventory, 75% of secondary copper smelters are considered to be area sources of HAPs. Since EPA has built expertise outside the ICCR process in dealing with secondary metal recovery units, he Committee recommends that copper recovery units, as well as precious metal recovery units, be considered by EPA for MACT development outside the ICCR process and that secondary metal recovery units be given no furhter consideration under the ICCR.

ATTACHMENT IV

INDUSTRIAL COMBUSTION COORDINATED RULEMAKING FEDERAL ADVISORY COMMITTEE

Boilers Emissions Testing
Phase I

1.0 INTRODUCTION

The Industrial Combustion Coordinated Rulemaking (ICCR) Federal Advisory Committee (a.k.a. ICCR Coordinating Committee) recommends that additional hazardous air pollutant (HAP) emissions data be gathered for boilers. The boiler source category is large and highly variable. The ICCR ICR Database shows that boilers combust roughly 50 types of nonfossil materials and wood materials, in addition to fossil fuels. The ICCR Emissions Database currently contains no HAP emission test data for most types of nonfossil materials and limited data for various types of wood-fired boilers. While the ICCR ICR Database indicate some additional test reports are available and EPA is following up on these, there will still be data gaps on emissions from nonfossil materials.

The ICCR Coordinating Committee recommends that EPA undertake a materials analysis program, as outlined in this report, and preliminary planning activities related to emission testing, as also outlined in this report. In order to obtain additional emissions data (both HAPs and criteria pollutants), the Committee recommends this Phase I plan for materials analysis and emissions testing of boilers. The Committee has developed this Phase I test plan with the knowledge that resources under ICCR are extremely limited. Therefore, the Committee has developed this Phase I test plan as one that is achievable given the budget constraints within the ICCR process. The Phase I Test Plan does not address all the questions that should be answered regarding emissions from boilers and the effectiveness of potential maximum achievable control technology (MACT). However, the results of this Phase I test plan will provide additional data, will address key data gaps that have been identified in the ICCR Emissions Database for boilers, and will provide information for prioritizing recommendatioins under Phase II stack testing.

1.1 <u>Overall Test Plan Strategy</u>

The Committee recommends a 2-phase test plan. Phase I would focus on filling obvious data gaps. Phase I would obtain more information on fuel/waste characteristics in order to better focus and prioritize further emission testing recommendations under a Phase II to fill remaining data gaps.

1.1.1 Why a Multi-Phase Test Plan?

Good utilization of resources

Characterize fuels/wastes in Phase I because easy, low cost, and fills many data gaps.
Field test boiler representing large population, with multiple fuels/wastes.
Extend resources to detailed emissions testing at later date, as needed.

Effective Method to Obtain Test Data with Large Variance in Population

Not similar equipment like Reciprocating Internal Combustion Engines or Stationary Gas

Turbines.
Not just gaseous and liquid fossil fuels (a few exceptions) like Process Heaters.
Fuel characterization provides definition on many dissimilarities.

Limits Number of Emissions Tests

Use fuel/waste characterization to categorize many sources.
Test only a few categories later instead of many "apparently different" sources now.

1.1.2 Fuels/Waste and Emissions Data

The Committee is using the following three steps to determine data gaps with regard to boilers that should be filled by testing.

Obtain data <u>directly</u> applicable

The Committee has reviewed the following data sources to obtain information on the types of fuels/wastes combusted in boilers and available emission test data:

- ICCR Inventory database.
- ICCR ICR database.
- ICCR Emissions database.

Utilize data <u>indirectly</u> applicable

The Committee is also reviewing data from other source categories that may be applicable to some subcategories of boilers. These data sources include:

- Utility HAPs.
- Municipal solid waste.
- Office of Solid Waste data (BIF boiler or incinerator tests).
- Other ICCR Sources.
- Literature search (conducted simultaneously with Phase I).

Define Data Gaps

Data gaps established by what above sources do not provide.

Use Test Plan to fill gaps.

1.1.3 Phase I Goals

Elements of Phase I Testing

Fuel/waste characterization.

Boiler emissions test.

Fill Gaps with the Greatest Need or Impact

Large number of sources with similar fuels/wastes.

Highly suspected HAP emitters.

Focus on Nonfossil Fuels

Develop subcategorization.

Refine HAPs list.

Perform Qualitative Evaluation of Potential Control Techniques

Fuel/waste characterization helps determine what control techniques are technically feasible or not feasible for a subcategory.

Predict Emissions from Fuel/Waste Characterizations

Input to developing Phase II emission test recommendations.

Control device performance.

Obtain Immediate Emissions Data for Large Category With Data Gap

Representative boiler.

Preferably multi-fuel boiler.

1.1.4 Strategy of Fuel/Waste Characterization

Define intrinsic properties of fuel/waste (C, H, O, S, N, halogens, moisture, heat content, metals, etc.)

Determine Similar Fuels/Wastes

Characterization will allow grouping of nonfossil fuels/wastes with similar characteristics. Some may look similar to fossil or wood materials.

Reduce size of "other" subcategory

Identify similarities in multiple fuel classifications.

Refine Nonfossil HAPs list

Identify materials with halogens or metals.

Predicted Emissions

Determine recommendations for Phase II testing (e.g., which fuels/wastes require further emission testing)

Perform qualitative evaluation of control techniques

1.1.5 Objectives of Phase I Testing

Choose Representative Boiler

Large population with no or little data.

Preferably multi nonfossil fuel boiler.

Determine Emissions

Low cost, broad spectrum organic analyses (FTIR).

Particulate matter.

Metals.

Dioxin and PAH.

Use in Identifying HAPs of Concern for Subcategory

Use to identify effects of fuel mixtures

Evaluate Control Device Performance on Pollutants

1.1.6 Objectives of Phase II Testing

The purposes of Phase II testing are to:

Fill remaining data gaps.

Establish performance of Control Techniques (i.e., control device performance and impact of combustion control techniques (good combustion practices) on emissions).

Evaluate impact of control techniques on criteria pollutants vs. HAPs.

Confirm HAPs of interest.

1.2 Components of the Phase I Test Plan

Phase I of the recommended boiler test program is designed to collect data in the most cost-effective manner that determines the emissions behavior of different fuels/wastes for which little or no data presently exists. Emissions behavior will be determined by a combination of the following methods:

Fuel/waste analysis, and

Emissions/control technique performance testing.

In cases where fuel/waste analysis or the emission knowledge collected during Phase I still does not provide clear emissions behavior for a given boiler scenario, then further emissions testing can be recommended in a Phase II testing program to collect additional data.

Once screening data has been gathered by one or more of the two methods described above, a recommendation can be made on additional data to be collected in Phase II for some fuels/wastes, boiler types, or control techniques. Parametric testing of these boilers may be required to determine whether emissions can be reduced by variation of operating parameters.

The recommended Phase I test plan contains two basic elements:

Recommendations for Fuel/Waste Sampling and Analyses
Recommendations for Emission Testing of a Combination Fuel-Fired Boiler

The recommended Phase I solid/liquid/gas fuel/waste characterization plan has two components:

Recommendations for Fuels/Wastes to be Collected and Analyzed
Recommendations for Specific Analyses to be Performed

The Recommended Phase I emission test plan has four components:

Recommendations for Boilers, Fuels/Wastes, and Emission Control Techniques to be Tested
Recommendations for Matrix of Operating Conditions to be Tested
Recommendations for Pollutants to be Measured During Testing
Recommendations for Test Methods to Quantify Emissions

Each of these components is discussed in the sections that follow. A summary table for the proposed emission test is provided in the final section of this recommended Phase I test plan.

1.3 Phase I Testing Goals

The Committee recommends the following goals for Phase I and/or Phase II emissions testing:

1. Acquire additional fuel/waste characterization data that can assist in grouping materials with similar characteristics and identify materials of particular concern to prioritize recommendations which may be developed for Phase II emission testing;

2. Acquire additional emissions data that can assist in determining the effect of cofiring fuels/wastes on HAPs formation;

3. Acquire additional emissions data that can assist in determining typical emissions for boilers throughout the operating range;

4. Acquire additional emissions data that can assist in determining the effectiveness and inter-relationships of combustion modifications in terms of controlling HAPs and criteria pollutants (namely, NO_x);

5. Acquire additional emissions data that can assist in determining the effectiveness of

post-combustion control devices to reduce HAPs;

The recommended Phase I test plan is designed around Goals #1 and 2, for the following reasons:

Fuel/waste characterization data on many of the fuel/waste materials currently combusted in boilers is a data gap in the ICCR Inventory, ICR and Emissions Databases for boilers.

This plan would accomplish required goals at a lower cost than a very extensive testing program to address the HAP effects from cofiring a multitude of combinations of fuels/wastes identified in the databases.

In addition, the Commmittee has further focused the recommended Phase I plan to address the effectiveness of a post-combustion control device on HAPs. The Committee recommends gathering emissions data for all HAPs included on the recommended target list of pollutants. The recommended Phase I test plan also will support Goal #5 in part, since simultaneous inlet and outlet (of the control device) emission sampling is recommended during the testing program.

2.0 SOLID/LIQUID/GASEOUS FUEL/WASTE CHARACTERIZATION

2.1 <u>Materials to Sample</u>

The Committee recommends that approximately 36 different fuel/waste materials be sampled and analyzed (see Appendix A) Each of the fuels/wastes selected is currently being burned in boilers based on the results of the ICCR ICR Database. For each material, the Committee recommends that samples from 1 to 6 facilities would be collected and analyzed. This results in a total of approximately 120 samples. However, some fuel/waste analyses were attached to the EPA ICR responses, included in emission test reports, or submitted by members. The Committee is reviewing these to see if they are complete and provide the needed information. A literature search is also being conducted to see if fuel analyses are already available for some of the fuel/waste materials. If information is obtained in these ways, the recommended number of samples may be reduced. The main focus of the recommendatioins is on a characterization of nonfossil materials and some wood materials. For boilers burning mixtures of materials, the recommendation is that each constituent should be separately collected and analyzed.

The materials recommended for fuel/waste analysis include:

Various solid materials such as tire-derived fuel, waste paper, plastics, treated wood, agricultural wastes;

Sludges from various industrial processes including pulp and paper industry sludges, finishing wastes, industrial wastewater treatment sludges;

Liquids from a variety of industries such as coke plant liquids, tall oil, alcohol-based liquids, waste oil;

Selected gases where additional information is required such as coke oven gas and blast furnace gas. (Due to the potential availability of data and higher costs of sampling and analyzing gases, analysis of gaseous materials may be further considered as part of Phase II recommendations rather than included under Phase I.)

The recommended materials and the recommended number of samples of each materials is included in Appendix A

2.2 <u>Sampling and Analyses Procedures</u>

The Committee recommends the use of generally accepted procedures (industry specific) or official methods (EPA, ASTM etc.) for the collection and analysis of the fuel/waste materials. Since the fuel mix will most likely vary for each boiler and among different boilers, the most cost effective and best technical approach to sample collection and analysis should be considered. This approach is necessary in order to have a consistent on-site sampling and off-site analysis to evaluate the results. Since the physical state of the fuels will be solids, liquids and/or gases, sampling protocols should be specific to each as well as the analysis, giving consideration to the chemical composition of the material.

Sampling procedures should be established for the various types of materials, considering their physical state. Where multiple fuels/waste materials are co-fired, each material should be separately sampled whenever possible. To account for inherent variation in the material, and save on analysis costs, multiple "samples" of the same materials could be from a facility and then composited for analysis (rather than collect a single sample that may not be representative). In other cases, such as gaseous fuels, a grab or an integrated sample may be the best approach. A sampling form should be developed to record the procedures used to take each sample, the time, the sampling location, and other relevant information.

While on-site, the Committee recommends that the following should be recorded on the log form information:

The type of plant/process;
The origin of the fuel/waste materials;
Known compounds or base ingredients, for example:

- for plastic laminate -- the resin type and properties.
- for process engineered fuels -- the types of paper and plastics used (e.g., PET, styrene, urethane).

Typical mixtures combusted; and
Any practices that are used to exclude certain materials prior to combustion.

Potential fuel analysis methods are provided as examples in Table 1. However, depending on the material, different or customized methods may be needed. The Committee plans to undertake a thorough review of existing methods specific to the targeted fuels/wastes and the most appropriate methods will be recommended. In those cases where no method exists, a customized method may have to be developed implementing all appropriate quality control (QC) measures to demonstrate the accuracy of the results and the precision of the method. Such QC measures could include matrix spikes and analysis by the method of standard additions.

For all solid and liquid fuel/waste materials, the Committee recommends that the following analyses from Table 1 should be conducted:

Ultimate analysis;
Metals;
Heat content;
Moisture content; and
Total organic and inorganic halogens.

Table 1. Possible Fuel Analysis Test Method

Analysis	Test Method	Constituent	Conditions	Fuel Phase (solid(S)/liquid(L)/ gas(G)
Ultimate	ASTM-3176,3177,3178	Carbon, Hydrogen, Sulfur, Nitrogen, Oxygen, Chlorine		S, L, G
Metals in Fuel, (in ashed sample)	ASTM D3683 (solids), ASTM-D482 (liquid) to ash, SW846 methods to sample metals, e.g, ICAP 6010, 7470 (for Hg), or NAA	As, Be, Sb, Cd, Cr(total), Cu, Pb, Mn,, Hg, Ni, Ag, Zn; Probably also Al, Fe, K, Si, Na, P, V, calcium		S, L
Heat Content	ASTM-D240, 2015		As received basis, dry basis and wet basis	S, L, G
Moisture Content	ASTM D3302 (solids), ASTM-D271, or ASTM-095 if volatile liquids, or water content by Karl Fisher, ASTM-D1774			S, L
Total Halogens	SW846, M5050, 9056 (organic)	Chlorine, Fluorine, Bromine, Iodine	Organic and Inorganic	S, L, G
Particle Size	D422, D293			S
Viscosity	ASTM-D455			L
Specific Gravity	ASTM-D1298			L
Bottoms, sediment, and water	ASTM-D96, D473, D4006			L
Organics	GC/MS methods	Organic compounds		S, L, G

The Committee recommends that the other analyses in Table 1 should be conducted for materials as appropriate depending on their physical state and expected composition. For example, for some types of materials, the Committee recommends that the following should be analyzed:

Extractions for pesticides and PCBs;
Extractions for Plastic monomers, if appropriate; and
Various preservatives for materials such as treated wood.

Each of the three sample matrices (for solids, liquids, and gasses) are briefly discussed below. See Appendix Bfor more detailed information on the analyses recommended for each type of material.

Solids

A large portion of the fuel/waste material combusted will be wood or wood products or sludges (semi-solids) containing wood fibers or wood products. The Committee recommends that these materials be characterized as to heat content (BTU), metals content, chloride content, ultimate analysis, moisture content, and density. If any of the wood has been chemically treated with a preservative, then additional testing is recommended to determine qualitatively and quantitatively the specific compound(s). This could involve solvent extraction following EPA Method 3050 and subsequent analysis by gas chromatography/mass spectrometry (GC/MS). If metals are to be determined, the Committee recommends that the sample first be digested to solubilize the metals and then the solution analyzed by standard EPA methods. The digestion step may be accomplished by identifying a method that has been developed specifically for this matrix. If sludges are involved, the Committee recommends that the sample be filtered to remove the water. The two fractions (filtered solids and water) should then be analyzed separately.

The analysis of other types of solids, such as plastic materials and automotive tires, may present unique situations and may need to be addressed on an individual basis. In these cases, for example, metals content could be determined using the specialized analysis technique of neutron activation analysis (NAA). NAA requires minimal sample preparation time and can provide detection limits that are equivalent or lower than standard wet chemical methods for metals analysis.

Liquids

Liquid samples can be generally divided into two groups; aqueous and organic. Different approaches to sample preparation and analysis should be considered for these two groups. Waste organic solvents are routinely characterized for heat content and chloride content before being combusted. The Committee recommends that compound-specific composition be determined by dilution with an appropriate solvent and should be analyzed by GC/MS following EPA Method 8270. In many cases, the chemical composition is known prior, especially when a particular waste stream is generated by the facility itself. This could preclude the need for such an analysis. Aqueous samples could be characterized for organic compounds by first preforming a liquid/liquid extraction with an appropriate solvent such as dichloromethane (methylene chloride) followed by analysis by GC/MS. Metals content could be determined following standard EPA methods such as Method 6010 (inductively coupled argon plasma spectroscopy, ICAPS).

Gases

The composition of gaseous streams can vary widely in complexity. Natural gas is a simple matrix and well characterized, whereas coke oven gas is very complex and contains, among other things, benzene, toluene, xylenes (BTEX), napthalene, polynuclear aromatics, and various sulfur compounds. Therefore, gas streams may need to be addressed on an individual basis. Generally, the Committee recommends that gaseous streams be sampled using an EPA sampling train consisting of a heated probe, heated filter for the removal of particulate matter, a sorbent resin and a series of impingers followed by a vacuum pump and a dry gas meter. To determine the composition of a gas stream for compounds with boiling points less than approximately 130 EC, the Committee recommends that Tenax resin be the sorbent material. For most compounds with boiling points greater than 100 EC, the Committee recommends that XAD-2 resin be the sorbent of choice. In both cases, after preparation, the Committee recommends that the samples be analyzed by GC/MS. This approach allows the collection of an integrated sample over a specific time period and concentrates specific compounds that may be otherwise too low in concentration to detect. Another approach is to collect a grab sample in an inert bag (Teflon or Tedlar) and perform an analysis by injecting a known volume of the sampled gas directly into a GC/MS or a gas chromatograph equipped with a flame ionization detector (GC/FID). In this case the compounds of interest are usually at the ppm level or higher. The grab sampling method would not allow detection of lower concentrations. Another alternative would be analyze the gas sample by fourier transform infrared spectroscopic (FTIR) techniques.

3.0 RECOMMENDED BOILER, FUELS/WASTES, AND EMISSION CONTROL TO BE TESTED

3.1 Boiler

The Committee recommends that only one boiler be tested under Phase I. The boiler should be selected to represent a possible subcategory of boilers. A stoker type boiler should probably be selected because it is the most common type of solid material burning boiler. The boiler should be permitted to co-fire solid non-wood, nonfossil materials as primary or secondary fuels. The boiler should not burn waste off-gases during the testing.

3.2 Fuels Wastes

The Committee recommends that a co-fired unit burning a primary fuel along with other nonfossil fuels be selected to be tested. Testing would provide emissions information on commonly fired nonfossil materials.

3.3 Emission Controls

The Committee recommends that the selected boiler be tested with an emission control device that has been identified as possible maximum achievable control technology (MACT). To date, the Committee has not identified possible MACT for boilers.

4.0 RECOMMENDED MATRIX OF OPERATING CONDITIONS TO BE TESTED

The Committee recommends that the selected boiler be tested over a range of fuel/waste mixtures. The test might include testing up to 3 different non-fossil fuels/wastes or mixtures. The Committee has not yet developed recommended operating conditions to be tested. It is estimated that testing of each fuel/waste mixture or operating condition would require approximately 3 days. Time should be allowed to reach stable operation with each new mixture or condition.

The Committee recommends that a boiler "expert" be on-site during all testing to monitor operating parameters and ensure that the testing is conducted at representative conditions. Process conditions should be monitored during the test.

5.0 RECOMMENDATIONS FOR POLLUTANTS TO BE MEASURED DURING TESTING

The Committee recommends that emissions data for both hazardous air pollutants (HAPs) and criteria pollutants be collected before and after the emission control device using inlet/outlet testing.

Once a boiler has been selected, the Committee will develop recommendations for the HAPs and criteria pollutants recommended for measurement during testing based on the principal pollutants that are reasonably anticipated to be emitted from the boiler. The pollutants that could be analyzed for using available test methods are also being considered. If an additional pollutant could be analyzed with negligible additional costs using the same test methods then it may be included in these recommendations.

The Committee recommends that emissions data for the following criteria pollutants and HAPs be collected:

carbon monoxide (CO);

nitrogen oxides (NOx);

total hydrocarbons (THC);

particulate matter (PM) and PM_{10}[1] ; and

sulfur dioxide (SO_2).

Several HAP pollutants including selected metals and organic HAPs.

Diluent gas (oxygen, carbon dioxide, and moisture) measurements should also be made.

6.0 RECOMMENDED TEST METHODS TO MEASURE EMISSIONS DURING

[1]Test methods for fine particulate matter (e.g., PM_{10}, $PM_{2.5}$) are being investigated.

TESTING

The Committee may develop recommendations for the test methods and detection limits used for emissions testing at a later time.

7.0 PRIORITIZATION

The Committee has designed this recommended Test Plan to give priority to obtaining additional emission information addressing key data gaps and providing information for prioritizing and minimizing recommendations for Phase II stack testing.

8.0 ESTIMATED COSTS

Appendix C contains information on the estimated costs of the recommended Phase I test program. The fuel/waste analyses portion could cost approximately $448,000 to $547,000.

The costs of the fuel/waste sampling analysis portion may be reduced. The Committee is reviewing fuel/waste analyses attached to the EPA ICR responses, included in emission test reports, submitted by members, and performing a literature search. To the extent data are available from these sources, the number of samples would be reduced. Composit analyses or reducing the number of analytes for some materials could also reduce costs.

The costs do not include sampling and analyses of the gaseous materials listed in Appendix B. Analyses and emission data are likely to already be available for the gaseous materials. The cost of sampling and analyzing for metals and organics in gaseous materials is more expensive than for liquids and solids, and may require on-site testing using a sampling train. Due to the potential availability of data and the costs, recommendations for gaseous material sampling will likely be deferred for consideration under Phase II.

9.0 SUMMARY OF PROPOSED EMISSION TEST

Recommended Boiler Subcategory:	Recommendations To Be Developed
Recommended Boiler to be Tested:	Stoker, ___ million Btu/hr
Recommended Fuel:	Recommendations To Be Developed, preferably multiple nonfossil fuels/wastes
Recommended Control Device:	Recommendations To Be Developed
Recommended Pollutants to be Measured:	
Criteria Pollutants:	NO_x, CO, THC, PM[1], SO_2
Hazardous Air Pollutants:	Recommendations To Be Developed
Recommended Test Methods to be Used:	Recommendations To Be Developed
Recommended Operating Conditions to be:	Recommendations To Be Developed

[1]Methods for fine particulates are being investigated.

APPENDIX A

List of Materials Recommended for Fuel/Waste Analysis and and Recommended Number of Samples

Material	Number of Boilers Combusting Material[a]	Percent of Boilers Co-firing Material	Typical 2-digit SIC codes	Number of Plants to Collect Samples From[b]	Comments
Gases:					
1. Coke oven gas	97	99%	32, 33	3	Fuel analysis/description for 8 facilities sent with surveys.
2. Blast furnace gas	90	99%	33, 49	3	Fuel analyses for 5 facilities in surveys.
3. Biogas	50	92%	20, 26, 28, 33, 49	5	May be some data available, some units may be covered by separate sewage sludge MACT.
4. Landfill gas	20	90%	49, 33, 28, 22, 20	3	Have some data available
5. Medium Btu gas; 308 Btu/scf Rectisol waste gas; 53 Btu/scf	3	100%	49	1	Low priority. Fuel analyses provided with survey. Review, contact facility if needed.
6. Process gas-vol with a boiling range of 70-80 F	2	100%	28	1	Low priority. Contact facility to see what this is.
Liquids:					
7. Waste Oil	>108	91%	various	3	May have sufficient data.
8. Coke plant liquids	>7	100%	33	3	
9. a. Tall oils and turpentines	10	100%	28, 26	3	Fuel analysis for one facility sent with survey.

Material	Number of Boilers Combusting Material[a]	Percent of Boilers Co-firing Material	Typical 2-digit SIC codes	Number of Plants to Collect Samples From[b]	Comments
b. Tar oils	5	60%	49	3	Fuel analysis in survey.
10. Alcohol-based liquids	6	83%	28, 30, 14	3	Fuel analysis for 2 facilities in survey.
11. Transformer dielectric fluid	1	100%	49	1	Fuel analysis provided in survey. Review, contact facility if needed.
Sludges and Solids:					
12. Paper pellets, process engineered fuels	18	100%	49, 26, 81, 92	4	Members may have some information available. Fuel analysis for 4 facilities in surveys.
13. Recycled papermill rejects, paper recycling plant rejects	4	100%	26	3	Fuel analysis for 1 facility in surveys.
14. Packaging waste materials (cardboard, box, paper, wood)	10	100%	39, 25, 24, 26, 35, 49	6	
15. Liquid solution of dyes	3	100%	20	3	
16. Solid waste from finishing operations, waste from spray booth cleaning	4	100%	25	3	
17. Paper mill sludges	39	100%	26, 28, 49	3	
18. Waste activated biological sludge from brewery wastes	2	100%	49	1	
19. Wastewater treatment sludges from various industries	89	100%	24, 26, 28, 37, 49, 82	6	

Material	Number of Boilers Combusting Material[a]	Percent of Boilers Co-firing Material	Typical 2-digit SIC codes	Number of Plants to Collect Samples From[b]	Comments
20. Waste paper	7	57	24, 27, 26	3	
21. Tires	59	91%	20, 24, 26, 35, 37, 49, 81	3	May be some data available.
22. Petroleum coke	10	100%	26, 29, 49	3	May be some data available.
23. Decorative laminate/cast polymer scrap	8	100%	25, 30	3	Member may have some data.
24. Plastics	8	87%	26, 28, 30, 38, 80	5	Member may have some data.
25. Dried resin & wax from OSB manufacturing process, on spec oil spill absorbent material, similar heating value to green bark	3	100%	24	1	Description in survey attachment.
26. Hydrocarbon soaked soil	3	100%	29	1	See if this is at an Asphalt Plant/covered by another MACT.
27. Bagasse	20	100%	20	3	Member is collecting samples and emission test information, so probably do not need to sample.
28. Peat	3	100%	49	1	May be some data available.
29. Rice hulls	c	--	20, 28	3	
30. Shells (peanut, almond, walnut)	c	--	01	3	
31. Corn stalks	c	--	28, 20	3	
32. Creosote treated wood	14	93%	24, 49	3	Fuel analysis for 1 facility attached to survey.

Material	Number of Boilers Combusting Material[a]	Percent of Boilers Co-firing Material	Typical 2-digit SIC codes	Number of Plants to Collect Samples From[b]	Comments
33. Pentachlorophenol treated wood	2	100%	--	1	
34. Other treated wood (including mixed construction debries)	d	90%	20, 24, 25, 26, 28, 49, 72, 82, 86, 92	3	Members identified mixed construction debris as a potential material to sample to fill data gaps.
35. Dry wood	d	-	24, 25, 50	3	Members identified dry softwood (pine) as a potential material to sample to fill data gaps. Some data are available for dry hardwood.
36. Timber Products	d	-	24, 25, 26, 28, 29, 49, 50, 82	18	Members suggested collecting 3 samples of each of the following materials to fill data gaps: green hardwood, green softwood, tree trimmings/ municipal clean-up waste, mostly clean bark, pulp and paper by products, whole tree (chips). Some data are available for various timber products.

[a]Based on survey database responses. Actual number may be higher, because some waste descriptions overlapped or were unclear. Also, units burning certain fuels [e.g., only bagasse or only sewage sludge and digester gas (biogas)] were not required to fill out the EPA ICR.

[b]The recommendations for the number of plants which samples should be collected from was developed as follows. A minimum of 3 plants should be sampled to allow statistical evaluation and account for variation among sites. (If the material is known to be combusted at only 1 or 2 sites, only 1 or 2 sites should be sampled.) If the material is combusted by plants in multiple SIC codes and the characteristics of the material are likely to vary by SIC, at least one plant per SIC code should be sampled.

[c]Some ICR responses that indicated agricultural waste did not provide a description, so the number of boilers burning each type is not available. Members developed the 3 subcategories shown based on their knowledge of Ag waste combustion.

[d]Wood within these categories is burned in hundreds to thousands of boilers. An exact count was not provided because it was not needed for purposes of developing recommendations of whether to sample these materials.

APPENDIX B
Recommended Fuel/Waste Sampling and Analysis Methods

1.0 INTRODUCTION

Boilers combust fuels/wastes having a wide variety of physical and chemical properties. These fuels/wastes include national gas, refinery fuel gas, other industrial gases, fuel oils, coal, tire derived fuels, process engineered fuels, paper, plastics, industrial sludges, bagasse, other agricultural materials, wood, and wood products. The recommended Phase I test program would include fuel/waste sampling and analyses to screen a large number of materials, particularly nonfossil materials. The results of these fuel/waste analyses would be used to group materials with similar characteristics, identify materials of particular concern, and thereby prioritize recommendations for Phase II emission testing. This document provides recommended guidelines for sampling and analyzing fuels/wastes fired in industrial, commercial and institutional boilers. The objective of this document is to introduce the reader to basic fuel/waste sampling and analytical strategies and procedures and provide references for more specific test methods as the fuels/wastes and sources to be characterized are determined. This document does not attempt to provide the reader with specific sampling and analytical strategies for every type of fuel/waste stream that may be encountered.

Many of the fuels/wastes under consideration are not homogenous and an understanding of the fuel/waste properties and processing may be necessary to develop protocols for collection of a representative sample. For many of the fuels/wastes it is likely that information from industry experts and fuel/waste sampling site representatives will be needed to develop a site-specific Test Protocol. Therefore this document first presents recommended guidelines on what types of information should be collected and considered prior to collecting samples for a fuel/waste characterization program (Section 2). Section 2 also includes a discussion of recommended procedures for collecting fuel/waste samples. Recommended analytical procedures are presented in Section 3.

2.0 SAMPLE COLLECTION

2.1 Definitions

The following terms are used to generally characterized fuel/waste streams:

Representative sample - sample that exhibits the average properties of the whole stream.

Homogeneous fuel/waste - uniform composition throughout the fuel/waste. Any sample of the fuel/waste would be a representative sample.

Heterogeneous fuel/waste - the fuel/waste is not consistent in composition. There is variation between samples so a single sample of a size suitable for analysis is not representative of the property of concern.

Random heterogeneity - fuel/waste constituents are randomly distributed throughout the fuel/waste with respect to space and time.

Non-random (or stratified) heterogeneity - fuel/waste heterogeneity varies over space or time. Each strata has its own constituent concentration distribution and mean concentration levels.

Random sampling - a sampling strategy where every unit in the population has a theoretically equal chance of being sampled.

Composite Sampling - In composite sampling, a number of individually collected samples are combined into a single sample for analysis.

Segregation - fuel/waste is separated into groups with similar physical or chemical properties prior to sample collection or analysis.

Homogenization - to process the fuel/waste components into more similar physical or chemical forms through grinding, blending, etc.

2.2 Overview of Sampling Strategies

Most sampling and analytical guidance documents and methods that have been developed by EPA and ASTM are for fossil fuel and hazardous waste characterization. Guidance documents and test methods for fossil fuels provide a starting point for developing Test Protocols for homogeneous fuels/wastes while guidance documents and test methods for hazardous waste are a starting point for non-homogeneous fuels/wastes.

2.2.1 Pre-Sampling Planning

EPA SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, (chapter nine) discusses considerations important in development of a fuel/waste characterization plan. A sampling plan must start with a clear, concise outline of the regulatory and scientific objectives of the program. Data quality objectives (DQO) should be developed by and agreed to by all program decision makers. Establishment of DQOs is especially critical for development of a sampling plan for non-homogeneous fuels/wastes. Defining the DQOs also serves to force the thought and communication between decision makers and other participants that is required to develop a sampling and analysis plan for non-homogeneous fuels/wastes.

Data quality objectives that should be addressed include:

Confidence Interval
Precision
Accuracy
Detection Limits

The first goal of a sampling plan is the collection of a representative sample. The confidence interval indicates the degree of confidence that the sample collected is representative of the fuel/waste. Calculation of confidence intervals is described in Chapter 9 of EPA SW-846. A second goal of a sampling plan is assurance that a sufficient number of samples will be collected over a period of time to quantify the variability of the fuel/waste over time. Detection limits should be sufficiently low to detect levels of concern (e.g. health risk or regulatory limits).

2.2.2 Sampling Strategy

Several sampling strategies are available for obtaining representative samples with homogenous or random heterogeneous fuels/wastes. Selection of the proper strategy requires some knowledge of fuel/waste characteristics through process knowledge, previous sampling data, or analysis of pre-screening samples. The same methods may be utilized for more excessively stratified heterogeneous fuels/wastes but the statistical uncertainty and number of samples required will increase. In general, for a homogeneous fuel/waste, one sample is adequate to characterize the fuel/waste. A total of three samples are often collected to determine the sampling and analytical precision. Some form of random sampling is normally required to collect a representative sample of a non-homogenous (heterogeneous) fuels/wastes. With random sampling, every unit in a population (e.g., every location in a drum of fuel/waste) has an equal chance of being selected. ***Simple random sampling*** includes division of the population (or fuel/waste) by an imaginary grid, assignment of a sequential numbers to each division or location, and selection of sample locations through use of a random-numbers table. A random numbers table is used to prevent bias in selection of sample locations. Guidance on how to use a random number table for fuel/waste sampling is can be found in EPA's "Drum Handling Practices at Hazardous Waste Sites" (EPA, 1986).

For a fuel/waste that is known to be non-randomly (stratified) heterogeneous in it's chemical or physical properties, ***stratified random sampling*** is appropriate. With stratified random sampling, simple random sampling is applied to the various non-random strata of the fuel/waste. This sample collection method requires knowledge of the extent and areas of stratification in the fuel/waste. Specific data for each stratum would not be collected. The samples collected during random sampling can either be analyzed individually or as a composited sample. ***Composite sampling*** is utilized when an average or normalized value is required. The advantage of composite sampling is reduced analytical cost. The disadvantage is lose of information regarding the range of values in the fuel/waste.

Systematic random sampling is another probability type of probability sampling. With systematic sampling, the first sample unit to be sampled from a population is randomly selected but all subsequent samples are collected at fixed space or time intervals. The disadvantage of this sampling is collection of non-representative samples when cycles or changes in trends occur in the population. The advantage is convenience.

Authoritative sampling is a non-statistical sample collection method based on detailed knowledge of the fuel/waste. Authoritative sampling is not normally utilized since it is more prone to bias in specification of sample locations and frequency and the validity of the data cannot always be proven or quantified. Further information on statistical methods and examples of probability sampling techniques can be found in EPA's SW-846, Chapter Nine (EPA, 1992).

Development of a fuel/waste characterization plan is more difficult for excessively stratified heterogeneous fuels/wastes. Characterization of these excessively stratified heterogenous fuels/wastes presents a number of special problems including:

It is difficult (or impossible) to accurately and precisely characterize the population. In general, a greater number of samples will have to be collected relative to a homogenous fuel/waste to achieve a given level of certainty. The number of samples required can become quite extensive.

Customary sample segregation, compositing, and homogenization schemes may not be appropriate or acceptable.

Utilizing standard sampling methodology, collection of a representative sample of a fuel/waste with particles of varied physical sizes greater than one centimeter may require collection of tens or hundred of pounds of material.

Reduction of large sample volumes to tiny homogeneous aliquot required for analysis may be difficult.

Quantification of "hot spots" (localized contamination) is difficult / impossible without very extensive statistical sampling.

A discussion of statistical sampling strategies for these excessively stratified wastes is contained in references 5 and 6.

2.2.3 Number of Samples

The number of samples collected depends on the available resources, the required degree of confidence, and the objective(s) of the characterization activity. EPA's "A Rationale for the Assessment of Errors in the Sampling of Soils" (EPA, 1990) provides tables and a discussion for the number of samples that are required to obtain a certain level of confidence when the data are normally distributed or can be transformed to the normal distribution (random heterogeneous). It has been recommended that this guidance is also applicable to heterogeneous waste ("Characterizing Heterogeneous Wastes: Methods and Recommendations" (EPA, 1992)). If historical data indicates that inaccuracy or variability is increased in the preparation and handling of a sample, and this affects detrimentally the required accuracy, then more frequent sampling may be justified. If the fuel/waste to be sampled is containerized, the EPA-approved ASTM method D 140-70 for estimating the number of containers to sample should be consulted(4). EPA's "Waste Analysis Guidance for Facilities that Burn Hazardous Waste" (EPA, 1994) provides guidance on sample location for various situations(3).

2.2.4 Sampling Methods/Techniques

This section contains an overview of the various sampling techniques for liquid, solids and gases.

Liquids

The EPA and ASTM have developed sampling methods for liquids, including those for either containerized (drum, tank, or pond) or free flowing. A mixer may be required for liquids with immiscible liquid and solid phases. Sampling methods include:

Tap Sampling (ASTM D4057-9.3) - Good for free flowing liquids.

Coliwasa (Composite Liquid Fuel Sampler) (ASTM D 4057-9.6) - Used for sampling of liquids in drums, pits, tanks, or similar containers. It is not appropriate for high viscosity fluids.

Dipper (Dip Sampler) (ASTM D 4057-9.5) - Used for grab samples.

Weighted Bottle (ASTM 4057-9.7) - Not good for high viscosity liquids.

Glass Open Tube

Manual pumping (Peristalics, bellows, Diaphragm, or Siphon)

Solids and Viscous Liquids

Sampling method have also been developed for viscous liquids, slurries, sludges, and solids. Standard EPA sampling methods for solids as outlined in Chapter 9 of EPA SW-846 include:

Thief (“Grain Sampler” or Punch) - Used for sampling of dry powder or granular materials. Not for sticky materials or particles greater than 0.25 inch.

Trier or Corer - Used for depth sampling of sludge or moist, sticky solids. It is not appropriate for coarse or granular material.

Trowel, scoop, or spoon - Used for surface sampling of moist or dry solids.

Auger (Helical or Spiral) - Effective for depth sampling of packed solids. It produces a disrupted sample.

ASTM sampling methods include:

ASTM D-140 -- For sampling viscous liquids.

ASTM D-346 -- For sampling crushed or powdered solids.

ASTM D-420 -- For sampling soil or rock-like material.

ASTM D-1452 -- For sampling soil-like material.

ASTM D-2234 -- For sampling fly ash-like material.

Gases

Tedlar Bag -

3.0 ANALYTICAL METHODOLOGY

Test methods have not been specifically developed for every type of fuel/waste and required measurement. Therefore, it is anticipated that a test method developed for a specific fuel/waste will be applicable to other fuels/wastes having similar characteristics. For example, test methods for coal are expected to be applicable to other solid fuels/wastes. However, it is recommended that analytical labs be consulted prior to applying test methods to fuels/wastes for which the test method was not specifically developed.

4.0 REFERENCES

1. EPA, "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," SW-846, 4th Edition, 1992.

2. U.S.EPA OSWER, "Waste Analysis at Facilities That Generate, Treat, Store, and Dispose of Hazardous Waste: A Guidance Manual," OSWER 9938.4-03, PB94-963603, April 1994.

3. U.S.EPA, "Waste Analysis Guidance for Facilities that Burn Hazardous Wastes Draft," EPA Enforcement and Compliance Assurance (2224A), EPA 530-R-94-019, October 1994.

4. ASTM (American Society for Testing and Materials, "1994 Annual Bood of ASTM Standards," Philadelphia, PA, Annual Series, 1994.

5. U.S. EPA (United States Environmental Protection Agency), Rupp, G., and R.R. Jones, (editors), "Characterizing Heterogeneous Wastes: Methods and Recommendations," EPA/600/R-92/033 (NTIS No. PB92-216894), US EPA Office of Research and Development and U.S. Department of Energy, February 1992b.

6. Maney, J.P., "Characterizing Heterogeneous Materials," in "Environmental Monitoring Issues: Results of Workshops Held in July 1992 as Part of EPA's Eighth Annual Waste Testing and Quality Assurance Symposium," D. Friedman (editor), U.S. EPA Office of Modeling, Monitoring Systems and QA, and U.S. EPA Office of Solid Waste, EPA/600/R-93/033 (NTIS No. PB93-216075), March 1993.

7. DOE, "Preparation of Waste Analysis Plans Under the Resource Conservation and Recovery Act (Interim Guidance)," DOE/EH--0306, March 1993.

Appendix C

Estimated Costs to Conduct Recommended Phase I Testing

1.0 INTRODUCTION

This appendix presents cost estimates for the recommended Phase I fuel analysis and emission test program. These cost estimates are intended to provide a general cost range. Once the exact number and type of fuel/waste samples and locations (plants) and an emission testing site are selected and protocols are refined, more refined cost estimates can be developed.

2.0 FUEL/WASTE SAMPLING AND ANALYSIS COSTS

The recommended Phase I fuel/waste sampling and analysis costs will vary depending on:

The number of fuel/waste materials sampled;
The number of samples per material;
The number of plants from which samples are collected and their locations;
Physical state of the material and sampling method;
Types of chemical analyses conducted, and
Complexity of sample preparation portion of the analyses, which depends on characteristics of the material.

Approximate costs have been calculated based on:

The recommended number of solid and liquid fuel/waste materials and number of plants to sample;
The types of analyses recommended; and
The assumption that for a given fuel/waste material at a given plant, 3 samples will typically be collected and analyzed.

The costs do not include sampling and analyses of the gaseous materials, analyses and emission data are likely to already be available for the gaseous materials. The cost of sampling and analyzing for metals and organics in gaseous materials is more expensive than for liquids and solids, and may require on-site testing using a sampling train. Due to the potential availability of data and the costs, gaseous material sampling will likely be deferred for consideration under recommendations for Phase II. Other assumptions are noted in the calculations.

Total costs for the recommended Phase I fuel/waste sampling and analysis are estimated to range from approximately $448,000 to $547,000. Tables 2-1 through 2-4 present calculations of these costs. Table 2-1 shows costs to develop site/material-specific protocols, collect samples, and prepare reports. Table 2-2 presents analysis costs for solid/sludge materials. Table 2-3 presents analysis costs for liquid materials. Data reduction and QA costs are included in the analysis costs. Adding the totals from Tables 2-1, 2-2 and 2-3 result in a total cost range of $448,071 to $546,974.

Table 2-4 presents additional information used to develop these costs.

3.0 EMISSION TESTING COSTS

The cost of the emission test will be estimated when recommendations for the actual test conditions and pollutants to be sampled are developed.

The stack test cost estimate will consider the following factors:

Manual and instrumental methods used;

One Method 2 (stack gas velocity and flow rate) measurement per run (on inlet and outlet);

Simultaneous inlet/outlet testing for manual methods;

3 sets of measurement runs per process condition;

number of process conditions and fuel/waste mixtures to be tested;

2 runs per day of manual methods, plus one contingency, one setup and one teardown day. Two travel days are assumed; and

2 instrumental runs per day plus one setup, one teardown, and 2 travel days. No contingency days are included.

Table 3-1 gives the breakdown of the total testing cost by methods. Table 3-2 gives the breakdown by task.

Table 2-1. Management, Protocol Development, Travel, Sampling, and Reporting Costs

	Range of cost per site	Number of Sites[a]	Range for Total Cost
1. Management, contact site, arrange visit, develop site/material-specific sampling protocol.	$640-960[b]	52	$33,280 - $49,920
2. Travel to 40 sites by car, prepare test equipment, collect samples (average of 2 materials per site, 3 samples of each material).	$1,000[c]	32	$32,000
3. Travel to city by air, visit 5 plants in same area, collect an average of 2 materials per site, 3 samples of each material ($2,530 for first site, $1,000 for 4 additional sites = $6,530 for 5 sites).[d]	$6,530	4	$26,120
4. Generate report for each site to document materials sampled, sampling procedure, sampling log forms, analysis procedures, analysis results. Send copy to site.[e]	$480[b]	52	$24,960
TOTAL			$116,360 - $133,000

[a]Assume samples from 60 plants. Collection of samples of various solid and liquid fuel/waste materials are recommended from 105 plants, but most of the fuels/waste are cofired. Assume an average of 2 fuel/waste materials of interest per plant, so this involves vists to 52 rather than 105 plants. Assume 32 plants are within driving distanc. Assume the other 20 are located in 4 different cities/areas requiring air travel. Assume one would fly to the city for 1 week and drive to collect samples from 5 plants in that area.

[b]Taken from Table 2-4, items 2 and 4.

[c]For plants within driving distance, used the low end of the range on Table 2-4, item 3 ($820) and added $180 (3 labor hours) to collect 3 samples of a second material at the same plant, for a total of $1,000.

[d]$2,530 is the upper end of the range on Table 2-4, item 3 ($2,350) plus $180 to collect 3 samples of a second material at the same site. This cost includes air fare. The $1,000 represents the costs for each additional plant within driving distance (see footnote c).

[e]Data reduction costs are included in the analysis costs in tables 2 and 3 rather than under reporting costs.

Table 2-2. Solid and Sludge Analysis Costs

Type of Analysis	Analysis Cost Range for 3 Samples of Same Material from a Single Plant ($)[a]	Number of 3-set Solid Material Samples	Range for Total Costs ($)
Ultimate analysis	448 - 523[b]	89[c]	39,872 - 46,547
Heat content	155 - 176	89	13,795 - 15,664
Particle size distribution analysis	249 - 291	89	22,161 - 25,899
Total organic halogens	600 - 720	89	53,400 - 64,080
Metals	736 - 912[d]	89	65,504 - 81,168
Mercury	142 - 169	89	12,638 - 15,041
Pesticides or PCBs	513 - 627[e]	15[f]	7,695 - 9,405
Semi-volatile organics by Method 8270	1,020 - 1,620[g]	30[f]	30,600 - 48,600
Dioxin/furan by high resolution GC/MS	2,700 - 3,300[h]	12[f]	32,400 - 39,600
Total Cost for all Analyses			278,065 - 346,004

[a]Cost are taken from Table 2-4 unless otherwise noted. Labor hour costs for data reduction and review are included in these analyses costs rather than under reporting on Table 2-1.

[b]Added $50 to the ultimate analysis costs shown in Table 2-4 to add N and Cl analysis.

[c] Assume samples of the various solid and sludge fuel/waste materials would be collected from 89 plants.

[d]The low end of the range is taken from Table 2-4, ICPAES method for all metals. The high end represents the cost of NAA (based on telecon with NC State University) including a full QA/QC package. (ICPAES could also cost over $900 for materials that require complex sample preparation).

[e]Analysis cost of $150 per sample x 3 samples = $450 plus $120 (2 hours) for data reduction = $570. Assumed ± 10% to create range.

[f]Assume these additional organics analyses are done for a subset of the samples, depending on the type of fuel/waste being analyzed.

[g]Analysis costs range from $300 to $500 per sample x 3 samples = $900 to $1,500. Added $120 (2 hours) for data reduction, for a total of $1,020 to $1,620.

[h]Costs are approximately $1,000 per sample, or $3,000 for 3 samples, ± 10%.

Table 2-3. Liquids Analysis Costs

Type of Analysis	Analysis Cost Range for 3 Samples of Same Material from a Single Plant ($)[a]	Number of 3-set Liquid Material Samples	Range for Total Costs ($)
Ultimate analysis	448 - 523[b]	16[c]	7,168 - 8,368
Heat content	155 - 176	16	2,480 - 2,816
Viscosity	141 - 159	16	2,256 - 2,544
Specific gravity	128 - 143	16	2,048 - 2,288
Bottom, sediment and water	303 - 357[d]	16	4,848 - 5,712
Total organic halogens	600 - 720	16	9,600 - 11,520
Metals	736 - 912[d]	16	11,776 - 14,592
PCBs	513 - 627[e]	4[f]	2,052 - 2,508
Semi-volatile organics by Method 8270	1,053 - 1,287[g]	6[f]	6,318 - 7,722
Dioxin/furan by high resolution GC/MS	2,700 - 3,300[h]	3[f]	8,100 - 9,900
Total Cost for all Analyses			56,646 - 67, 970

[a]Cost are taken from Table 2-4 unless otherwise noted. Labor hour costs for data reduction and review are included in these analyses costs rather than under reporting on Table 2-1.

[b]Added $50 to the ultimate analysis costs shown in Table 2-4 to add N and Cl analysis.

[c]Assume samples of the various liquid fuel/waste materials will be collected from 16 plants.

[d]The low end of the range is taken from Table 2-4, ICPAES method for all metals. The high end represents the cost of NAA (based on telecon with NC State University) including a full QA/QC package. (ICPAES could also cost over $900 for materials that require complex sample preparation).

[e]Analysis cost of $150 per sample x 3 samples = $450 plus $120 (2 hours) for data reduction = $570. Assumed ± 10% to create range.

[f]Assume these additional organics analyses are done for a subset of the samples, depending on the type of fuel/waste material.

[g]Analysis costs of $350 per sample x 3 samples = $1,050 plus $120 (2 hours) for data reduction = $1,170. Assumed ± 10%

for range.

[h]Costs are approximately $1,000 per sample, or $3,000 for 3 samples, $\underline{+}$ 10%.

Table 2-4. Cost Model to Estimate Fuel Sampling and Analytical Costs: Three Samples of One Fuel (Draft)

Task/Activity	Estimated Cost ($)(1)		
1. Pre-test site visit.	410	-	2,180
2. Project management and Test Protocol preparation.	640	-	960
3. Prepare test equipment, travel to site, and collect three samples.	820	-	2,350
4. Reporting.	480	-	800
Total - Tasks 1 - 4	**2,350**	**-**	**6,290**
Ultimate analysis and data reduction for three liquid or solid fuel samples (C, H, S, O, ash, moisture.	398	-	473
Heat content analysis and data reduction for three liquid or solid fuel samples (HHV).	155	-	176
Fuel gas analysis and data reduction for three samples (composition (C, H, O, N), HHV, density, and compressibility factor).	546	-	654
Viscosity analysis and data reduction for three liquid fuel samples.	141	-	159
Specific gravity analysis and data reduction for three liquid fuel samples.	128	-	143
Bottoms, sediment, and water analysis and data reduction for three liquid fuel samples.	303	-	357
Particle size distribution analysis and data reduction for three solid fuel samples.	249	-	291
Total organic halogens analysis and data reduction for three liquid or solid fuel samples (F, C1, Br, I).	600	-	720
	Cost for all metals		
Metals analysis and data reduction for three liquid or solid fuel samples by ICPAES (see footnote 2).	736	-	872
Metals analysis and data reduction for three liquid or solid fuel samples by flame AAS (see footnote 3).	736	-	872
Metals analysis and data reduction for three liquid or solid fuel samples by GFAAS (see footnote 4).	995	-	1,189
	Cost per metal		
Metals analysis and data reduction for three liquid or solid fuel samples by ICPAES (see footnote 2).	85	-	99
Metals analysis and data reduction for three liquid or solid fuel samples by flame AAS (see footnote 3).	85	-	99
Metals analysis and data reduction for three liquid or solid fuel samples by GFAAS (see footnote 4).	115	-	136
Mercury analysis and data reduction for three liquid or solid fuel samples by CVAAS.	142	-	169

1. Low cost based on easy-to-access source within 50 miles of testing company and low cost lab. High cost based on difficult-to-access source within 1,000 miles of testing company and high cost lab. Pre-test site visit may not be required for all sources.
2. Metals include: Al, Sb, As, Be, Cd, Cr, Cu, Fe, Pb, Mg, Mn, Ni, K, Se, Ag, Na, V, Zn.
3. Metals include: Al, Sb, As, Be, Cd, Cr, Cu, Fe, Pb, Mg, Mn, Ni, K, Ag, Na, V, Zn.
4. Metals include: Sb, As, Be, Cd, Cr, Cu, Fe, Pb, Mn, Ni, Ag, V, Zn.

Table 3-1. Stack Test Cost Breakdown

Description	Estimated Cost ($ K)[a]
Manual methods sampling	TBD
Manual methods sample analysis	TBD
FTIR sampling and analysis	TBD
Direct interface GC/MS sampling and analysis	TBD
Total	TBD

[a]Includes respective contributions for site visit, QAPP and site-specific test plan preparation, field test, data review, sample analysis and reporting.

Table 3-2. Stack Test Cost Breakdown by Task

Task	Estimated Cost ($ K)
Site Visit	7
QAPP preparation	20
Site-specific test plan preparation	9
Field preparation	21
Field test	TBD
Field recovery	17
QA and sample analysis	TBD
Reporting	30
Total	TBD

ATTACHMENT V

INDUSTRIAL COMBUSTION COORDINATED RULEMAKING FEDERAL ADVISORY COMMITTEE

RATIONALE FOR DEVELOPMENT OF MACT FLOOR FOR EXISTING COMBUSTION TURBINES

Executive Summary

The ICCR Coordinating Committee has reviewed the existing inventory and emissions data in an attempt to identify a MACT floor for existing combustion turbines. Section 112 of the Clean Air Act defines the MACT floor as "... the average emission limitation achieved by the best performing 12 percent of existing sources (for which the Administrator has emissions information) ...". Starting with a database that represents in excess of 60 percent of the known non-standby turbines in the United States, the Committee first concluded that the data were representative of the source category. The Committee then analyzed a total of 70 tests contained in 46 source test reports, originating largely from California as a result of state toxics inventory programs. The Committee evaluated these source test reports for accuracy and completeness including calling facilities to fill in data gaps. The resulting emissions database was analyzed for any relationship between HAP emissions and some variable including size, load conditions, fuel type, operating and maintenance practices, use of some type of emission control technique or device, and combustor design. The Committee graphed most of the available emissions data for a variety of fuels, primarily natural gas and No. 2 fuel oil. Field gas and landfill gas were usually plotted for comparison purposes when the data were available. Except for operation at partial load, no relationship between HAP emissions and any other variable could be identified. The Committee also performed a separate detailed analysis of good operating practices (Appendix A) and concluded that no practical guidance could be given an operator to improve (lower) HAP emissions which was not already being done or which was not already designed into the equipment by the turbine manufacturer.

Conclusions

- There is no relationship that can be identified, with the exception of operation at partial load, between HAP emissions and any other turbine variable such as size, fuel type, operating and maintenance practices, use of any type of emission control technique or device, or combustor design. As a result, the apparent difference in HAP emissions which may exist among combustion turbines is due to inherent variability among turbines, not to specific differences in "performance." It is not possible, therefore, to identify a subset of existing combustion turbines which represents the "... best performing 12 percent ...".

- There are no data on emission reduction technologies or add-on control devices that are known to reduce HAP emissions in the emission database. Add-on exhaust control devices installed for any reason that may reduce HAP emissions are present in slightly more than two percent of the existing turbine population based on vendor estimates. Therefore it is not possible to develop a

MACT floor for existing combustion turbines based on these potential technologies.

- There are no practical operating practices that can be recommended that will impact HAP emissions from combustion turbines short of operating as close to maximum load as possible.

- Operation at partial load appears to increase HAP emissions. However, operation at partial load is necessary for load following applications.

MACT Floor Recommendation

Based upon an analysis of the of the EPA Inventory Database, EPA ICR Database, EPA Emissions Database, and other available data, the Committee has not identified a MACT floor for existing combustion turbines. Based on analysis of emission test results, however, the Committee believes that HAP emissions are correlated with operating load. Analysis of relevant data - collected through the recommended test program or from other means - may influence final recommendations of MACT standards. Having fully investigated the broad range of emissions data currently available to the Administrator on combustion turbines, the Committee concludes that it is not possible to identify a "best performing" subset of existing combustion turbines and, as a result, there is no MACT floor for existing combustion turbines.

RATIONALE FOR DEVELOPMENT OF MACT FLOOR FOR EXISTING COMBUSTION TURBINES

Purpose

The purpose of this document is to explain the rationale of the ICCR Coordinating Committee leading to the development of the maximum achievable control technology (MACT) floor recommendation for existing combustion turbines.

Available Information

Inventory information and emissions source test reports are available for use as a basis for the MACT floor determination. The inventory information is based on point source information from available databases such as AIRS, OTAG, and state and local agencies' databases. This information includes references to location, size, application, and other operating parameters for each unit. Emissions data are summarized from gathered test reports for HAPs and criteria pollutants. Only complete test reports were included in the emissions database.

CT Inventory Information

The ICCR Population database for turbines currently has inventory information on approximately 5,300 non-standby turbines. Estimates place the current turbine population at approximately 8,000 turbines. Therefore, the inventory database contains data on approximately 65% of the installed turbines in the United States. A significant percentage of these 8,000 machines are probably in standby service. Within the database, varying degrees of information are available for different turbine parameters. For example, there is information on the fuel type for all of the turbines in the population database. However, there is limited make and model data given for individual units; only 8% are populated with both make and model while 5% are populated with make only. There is also limited information on the capacity of the units in the database; approximately 34% have size information.

Several characteristics of the population database are important to the MACT floor analysis. These characteristics are listed below and discussed in detail in this section:

The population database is believed to be representative of the turbine user community;

The database shows no add-on controls specifically installed for HAP control; and

There are no references in the database to Good Operating Practices.

Representative Data – The inventory information contained in the ICCR database is believed to be representative of the turbine industry, primarily because of its comprehensiveness (65% of the existing units reflected). The database also includes both small and large turbines in different user segments (by SIC). A review of the user segments and their representation in the ICCR Population database indicates that the population distribution is reasonable and logical. The following table shows the industry segments included in the ICCR inventory database.

Industry Segment	ICCR Inventory Database*
Industrial	48%**
Utility	39%
Pipeline	13%

* Independent Power Producers (IPPs) are included in the Utility and Industrial segments.
** Includes units burning crude petroleum and natural gas, natural gas liquids, etc.

Add-On (Exhaust) Controls – The Committee looked at the inventory database for add-on post combustion exhaust controls and identified less than 100 entries using exhaust controls. No exhaust controls specifically installed/designed for control of HAPs were identified. The Committee, through vendor input, is aware of a small number of oxidation catalysts added for control of carbon monoxide that may have some HAP reduction potential, but this opinion has not been confirmed with actual testing. More significantly, the total number of units in the database equipped with post combustion exhaust controls of any type and for any pollutant probably represents less than two percent of the entire turbine population, far less than the 12 percent needed to establish the MACT floor for existing turbines.

Good Operating Practices – There are no references in the inventory database to good operating practices for combustion turbines. Additional information from vendors and stakeholders has been received to supplement the information in the inventory database. For instance, user and manufacturer stakeholders indicate that virtually all turbines are operated according to good operating practices, since combustion turbines, by manufacturer design, have little operator involvement and no operating parameters such as air/fuel ratio or timing for the operator to adjust, for instance. In addition, most turbines will not operate unless preset conditions established by the manufacturer are met. A paper developed from discussion of good operating practices is attached as Appendix A.

CT Emissions Database

The emissions data gathered for combustion turbines are based on reviewed emissions test reports for HAPs and criteria pollutants. The emissions database includes 70 source tests many of which involve replicate sampling and analysis runs. The Committee believes that the emissions database adequately represents the turbine population, and that these source test data are sufficient to conduct a MACT floor analysis. The number of gathered tests for HAPs by fuel type are as follows:

Natural Gas = 42;
Number 2 Fuel Oil = 12;
Digester Gas = 3;
Landfill Gas = 11;
Refinery Gas = 1;
Field Gas = 1.
Total Tests: 70

The sizes of the combustion turbines in the emissions database range from .8MW to 88MW, so small and large turbines have both been captured. The gathered test reports represent applications in industrial, pipeline, and utility sectors. The majority of the source tests were conducted in the State of California as part of the AB2588 (Air Toxics "Hot Spots" Information Assessment Act of 1987) program. The State of California is the only state with regulatory requirements for estimating toxic emissions from stationary combustion sources. Therefore, as expected, the California Air Resource Board and local agencies are the largest data source of HAP emissions from combustion turbines. The Committee contacted all air districts in the state of California and requested complete copies of available HAP test reports for combustion sources. Other states, including Washington, Texas, Pennsylvania, and New Jersey, and trade associations such as Western States Petroleum Association (WSPA) were also contacted for available source test reports.

Source test validity was established using a common set of criteria included in Appendix B. When possible, pertinent information identified as missing from these test reports was obtained by contacting the tested facilities. Only those source test data considered appropriate for use in evaluating HAP emissions were used in the MACT floor analysis. In addition, an outlier analysis was conducted, and it was concluded that no HAPs data should be excluded from the MACT floor analysis. A description of the development of the emissions database, including assumptions used in the calculations, is provided as Appendix C.

Analysis of the Emissions Database

General:

As stated previously, the Committee believes the emissions database is representative of the turbine population. A total of 46 source test reports containing 70 tests for HAP emissions are included in the database. The Committee estimates that the collective costs for performing the same source tests in the ICCR emissions database today, including coordination and engineering analysis, would be several million dollars.

The preliminary MACT floor analysis was based on normalized emissions in terms of mass emissions per unit energy input (lb/MMBTU). This is the most commonly used unit in the database. Another unit could have been used, such as mass emissions per energy output net, or lb/MW-hr net, but the database lacked complete information for this approach.

Subcategory Analysis:

The Committee evaluated several subcategories of combustion turbines that could exhibit different emissions characteristics. After discussion, only turbine size and fuel type were potential subcategorization candidates. Nevertheless, in the MACT floor analysis, the Committee explored five areas to determine if there were any relationships with regard to HAP emissions that could be identified from the EPA emissions database. The following five areas thought to influence HAP emissions were analyzed in detail (there is no particular significance associated with the ranking of these areas):

- Size
- Load Conditions
- Fuel Type
- Operating and Maintenance Practices
- Combustor Design

1. Size vs. HAPs:

As seen in Figure 1, a plot of formaldehyde emissions in lb/MMBTU versus turbine size, no discernible relationship can be identified between turbine size and the most common HAP (i.e., formaldehyde) for a variety of fuels. Generally, one would expect that higher firing temperatures result in lower HAP emissions. There is a general industry trend today to push for higher and higher efficiencies, which leads to higher firing temperatures across all turbine sizes since higher firing temperatures improve turbine fuel economy. Therefore, since firing temperatures are not directly related to turbine size, it is not surprising that a definable relationship linking HAP emissions to turbine size is not evident in the data presented in Figure 1. Formaldehyde variation can be as great as two orders of magnitude across most of the turbine size fields. In fact, upon closer examination of one of the poorer performing turbine units (with respect to formaldehyde emissions), it was found that when the same unit was tested later, it turned in among the lowest emissions levels. While there is no explanation for this change in performance, it is certain that turbine size was not a factor. Benzene emissions were also plotted versus turbine size, as shown in Figure 2. Again, no discernible relationship between this pollutant and turbine size can be identified for a variety of fuels. The CTWG notes that the abundance of data points at the very small size end of these graphs (Figures 1 and 2) indicates that the data are probably representative of the mix of large and small turbines in the universe.

The Committee also took a purely mathematical approach in analyzing the database to examine whether a relationship exists between formaldehyde emissions and turbine size. The least squares fit line shown on Figure 1 is essentially horizontal indicating little or no relationship; the correlation coefficient (r^2) is also very low (0.02), indicating a poor correlation (an r^2 of 1.0 indicates excellent correlation). The Committee did not attempt purely mathematical analyses on the balance of the data since no relationships were discernible in any of the remaining data based on visual inspection.

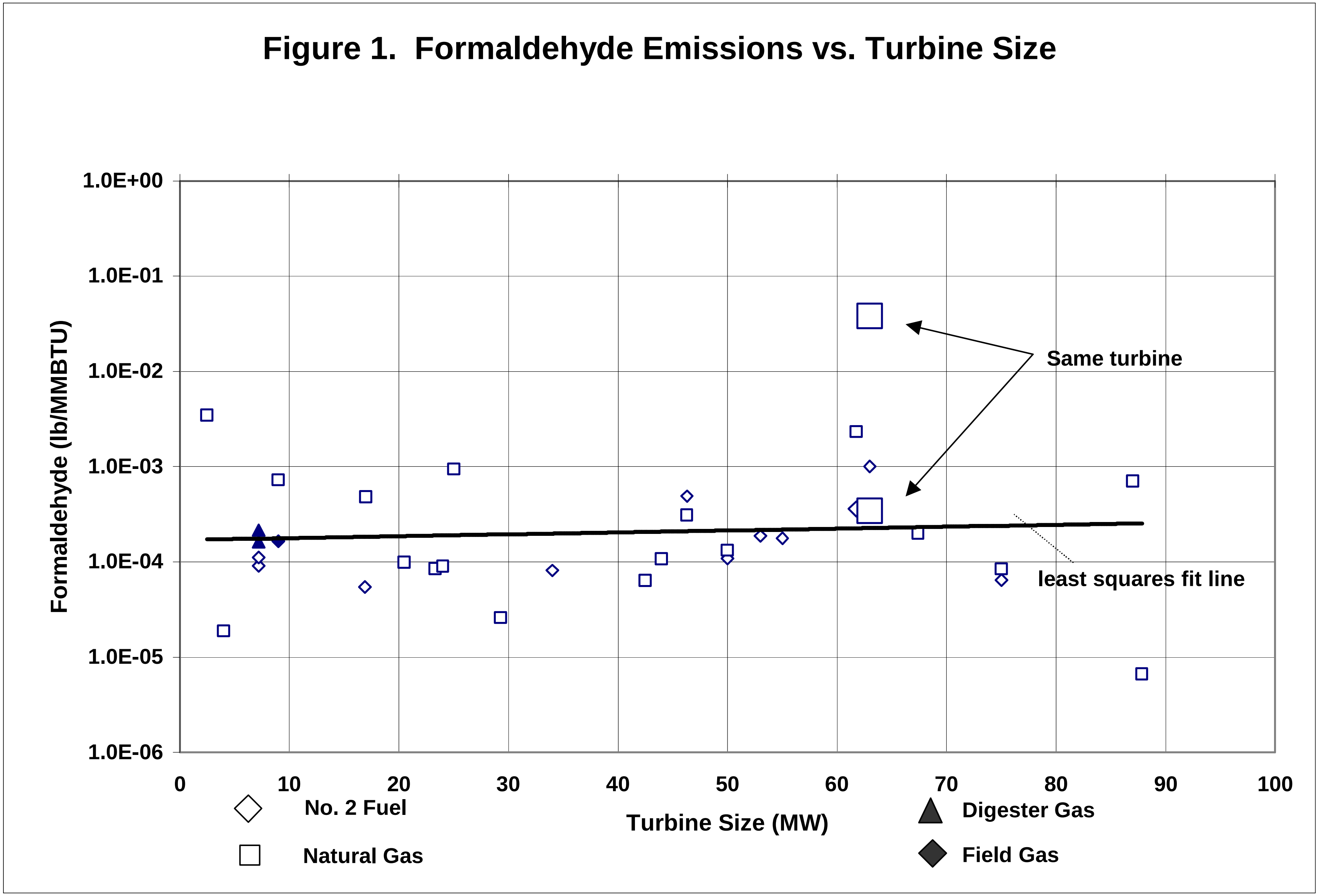


Figure 1. Formaldehyde Emissions vs. Turbine Size
Formaldehyde (lb/MMBTU)
1.0E+00
1.0E-01
1.0E-02
1.0E-03
1.0E-04
1.0E-05
1.0E-06
0
10
20
30
40
50
60
70
80
90
100
Turbine Size (MW)
Same turbine
least squares fit line
No. 2 Fuel
Natural Gas
Digester Gas
Field Gas

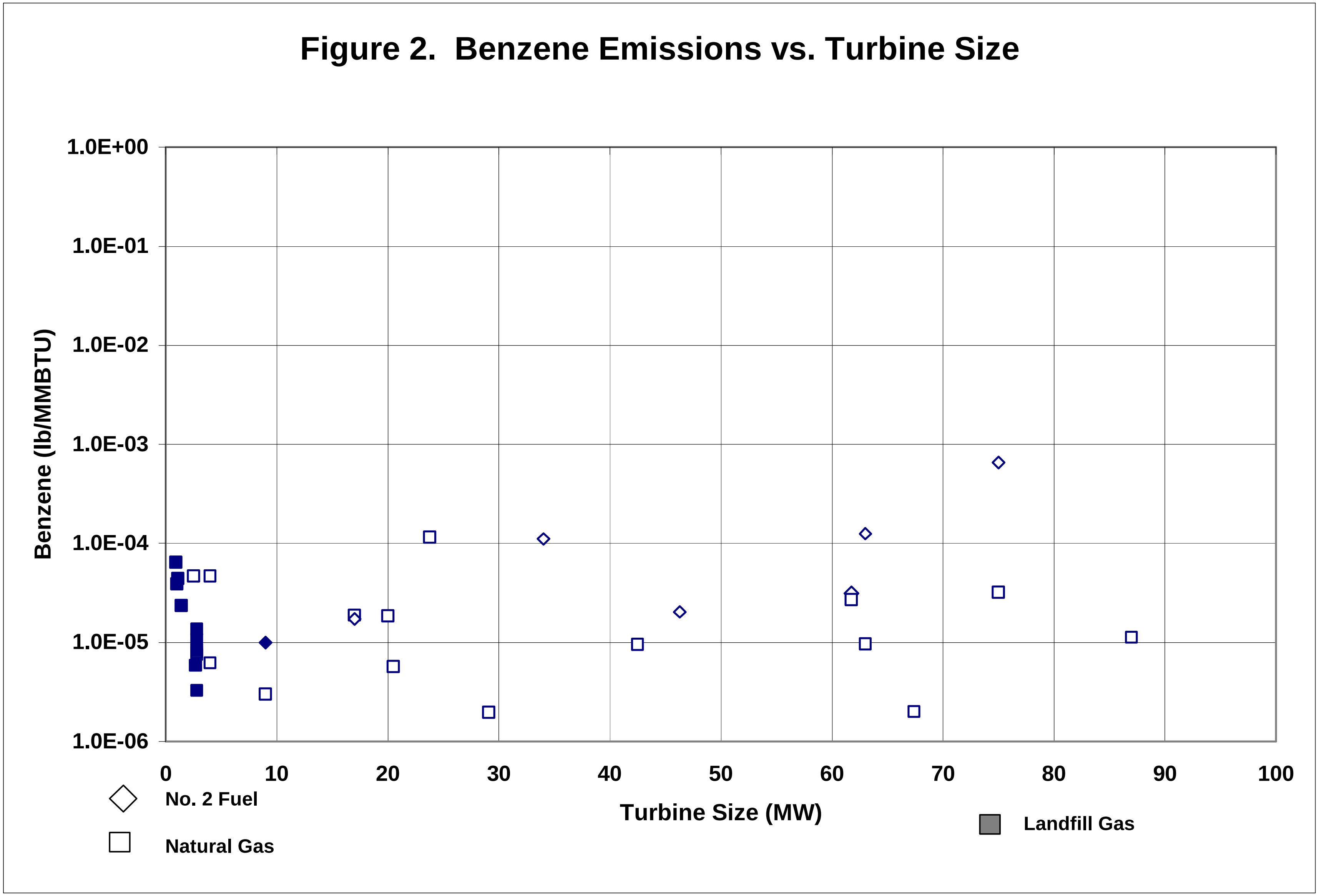


Figure 2. Benzene Emissions vs. Turbine Size
Benzene (lb/MMBTU)
1.0E+00
1.0E-01
1.0E-02
1.0E-03
1.0E-04
1.0E-05
1.0E-06
0
10
20
30
40
50
60
70
80
90
100
Turbine Size (MW)
No. 2 Fuel
Natural Gas
Landfill Gas

In an attempt to do a complete and thorough analysis, the Committee reviewed the available metals emissions data and plotted Cr(VI) versus turbine size on Figure 3, and concluded that no relationship could be identified. The Committee believes that one explanation of this phenomenon is that metals are not a product of combustion, but may be introduced through several routes, e.g., fuel, air, lubricating oil, etc. The Committee recognizes that turbine blade erosion may also be a contributing factor to metal emissions but the effects are extremely small over a long number of operating hours.

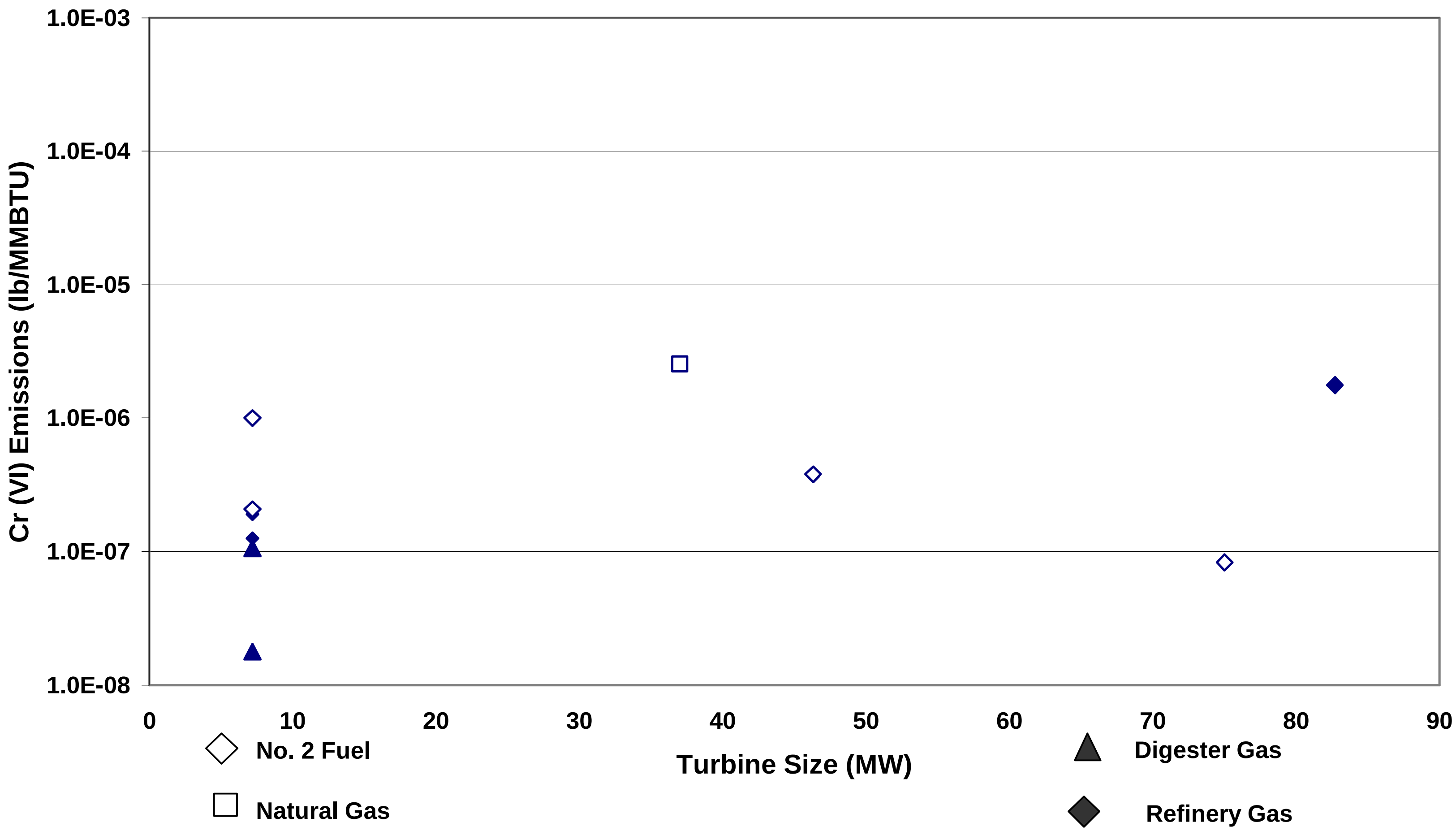
2. <u>LOAD vs. HAPs</u>:

The Committee is aware that most of the emission data contained in the EPA database is at full load. This is confirmed in Figure 4 when all the benzene data are plotted, excluding the GRI/EPRI data points described below. The stand-out conclusion is that the bulk of the HAP emissions data was collected at high load. The Committee also noticed that there is a considerable amount of emissions variability within the full load range for a variety of fuels. Figure 5 for formaldehyde supports this same conclusion.

The Committee acknowledges that combustion turbine load is a factor in HAP emissions. This is based on the results of at least one test program (GRI/EPRI) that showed increased HAP emissions at reduced load versus full load. Seven turbines were tested in this test program. One of the turbines was tested at four load conditions. The other six turbines were tested at the minimum and maximum loads at which the turbines normally operate. Figures 6A and 6B show the relationship between benzene and formaldehyde emissions, respectively, versus load for the turbines tested in the GRI/EPRI test program.

The Committee believes that the combustion turbine operator has no control over the HAP emission increases that can result when the turbine has to be operated at lower loads. The load varies in many industrial applications due to process requirements. An example is a combustion turbine used at gas pipeline compressor stations where the turbine load automatically follows the process load (i.e., load following). Since turbines are designed to operate most efficiently at high loads (i.e., between 80 to 100 percent load), turbines operate less efficiently and higher HAP emissions can result when the load goes below these higher load levels. Similarly, many electrical applications are load driven and restrictions on operating below certain load ranges are not a feasible option. Some turbine designers have attempted to correct this inefficiency at parial load operations by installing programmed, automatically-operated inlet guide vanes to spread out the best operating range down to lower loads and also by using cycle variations such as recuperators.

Figure 3. Chromium (VI) Emissions vs. Turbine Size



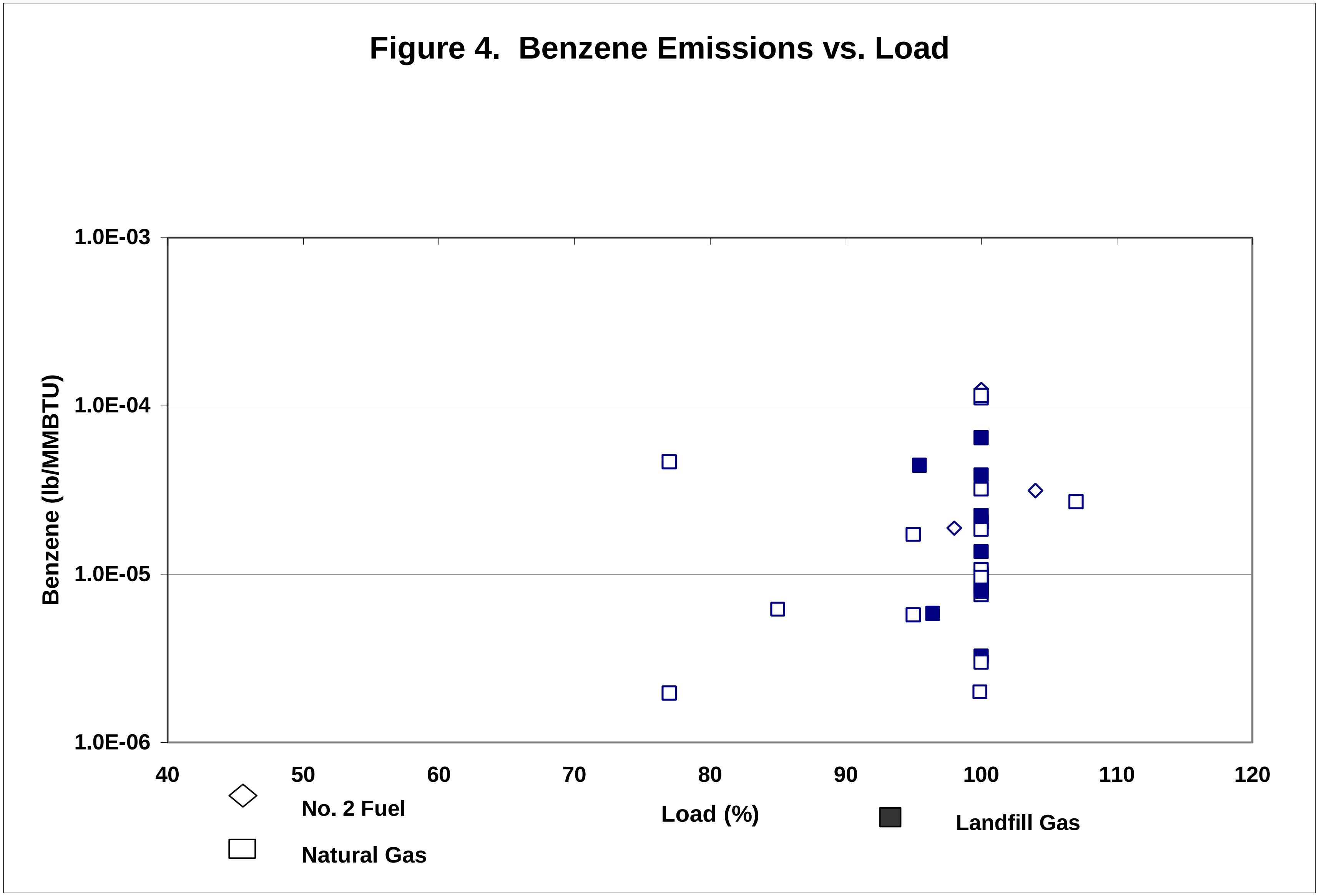


Figure 4. Benzene Emissions vs. Load
1.0E-03
1.0E-04
1.0E-05
1.0E-06
Benzene (lb/MMBTU)
40
50
60
70
80
90
100
110
120
Load (%)
No. 2 Fuel
Natural Gas
Landfill Gas

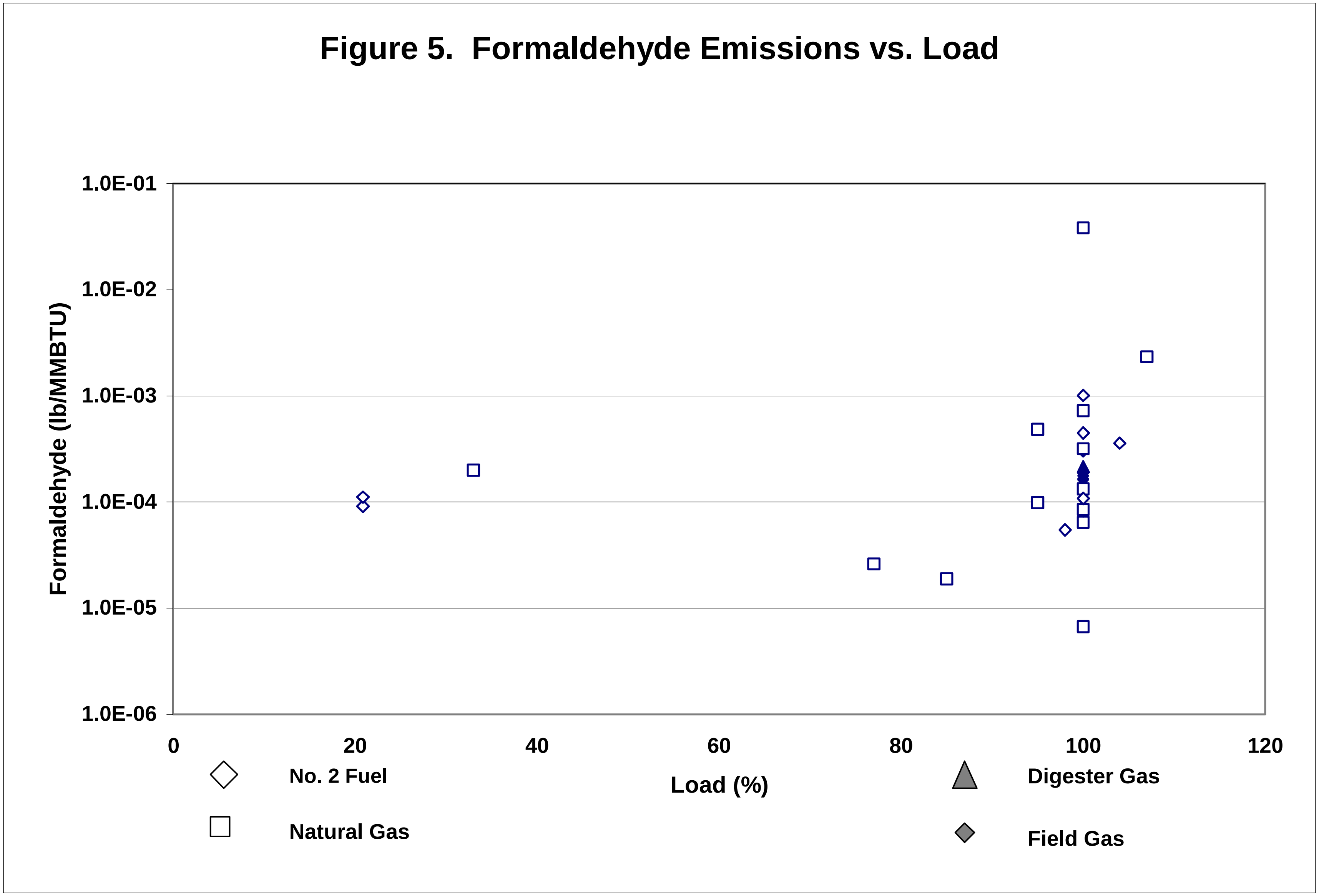


Figure 5. Formaldehyde Emissions vs. Load
Formaldehyde (lb/MMBTU)
1.0E-01
1.0E-02
1.0E-03
1.0E-04
1.0E-05
1.0E-06
0
20
40
60
80
100
120
Load (%)
No. 2 Fuel
Natural Gas
Digester Gas
Field Gas

Figure 6A. Benzene Emissions vs. Load (GRI/EPRI tests)

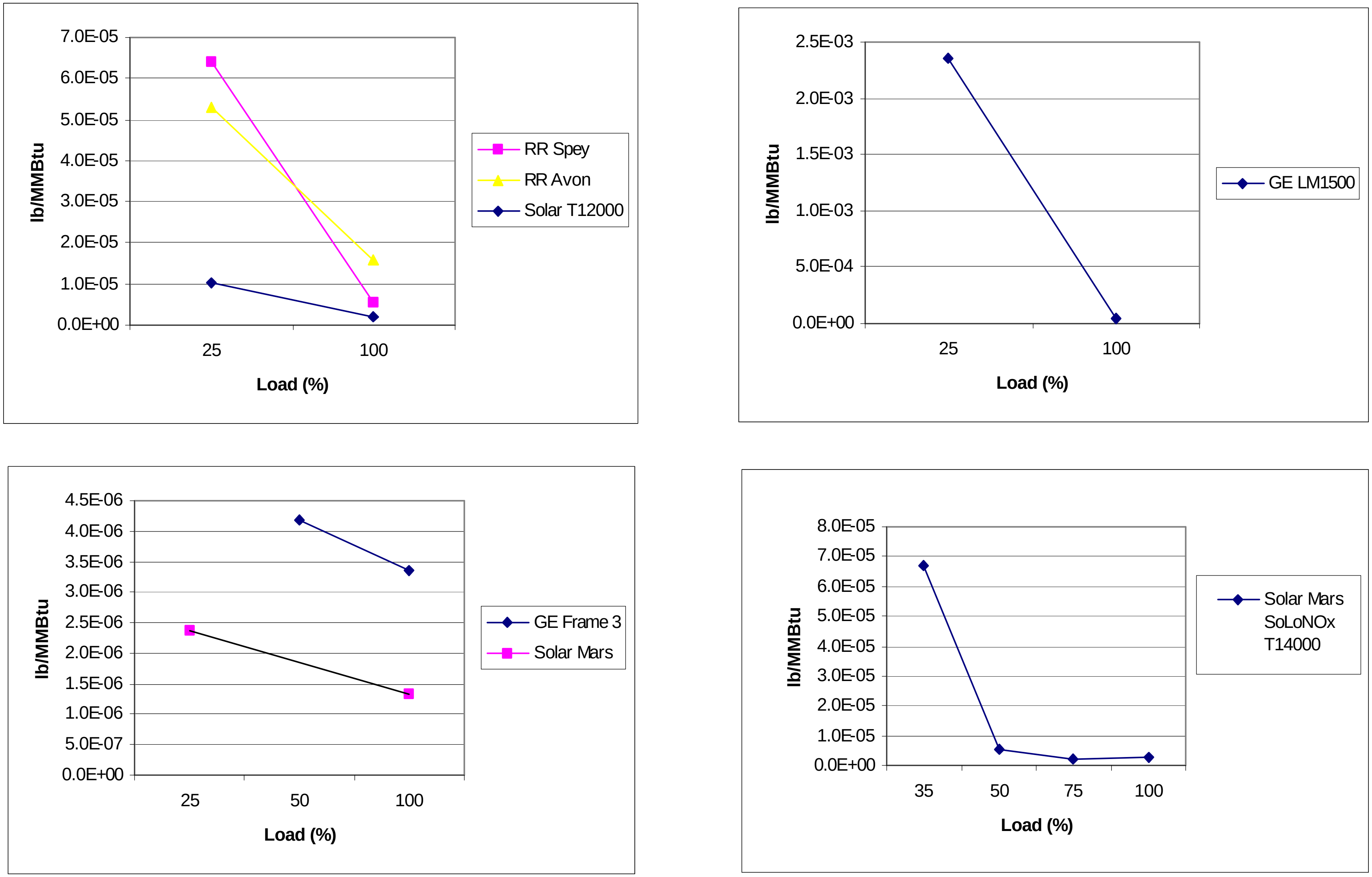
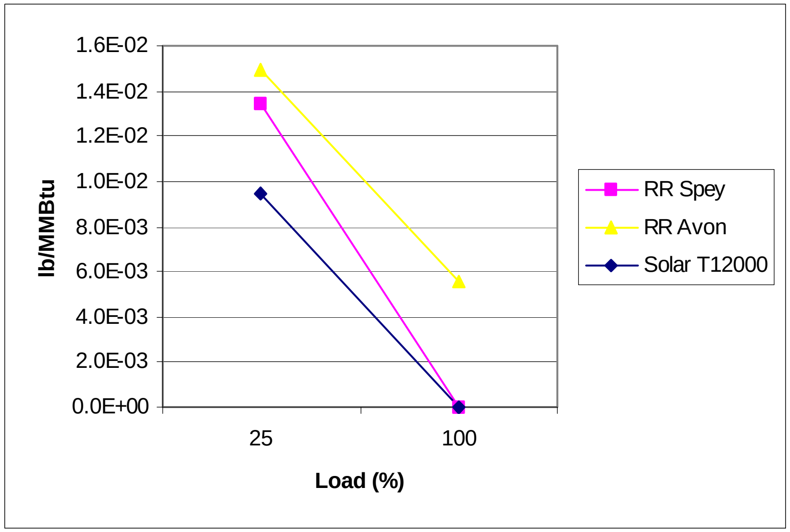
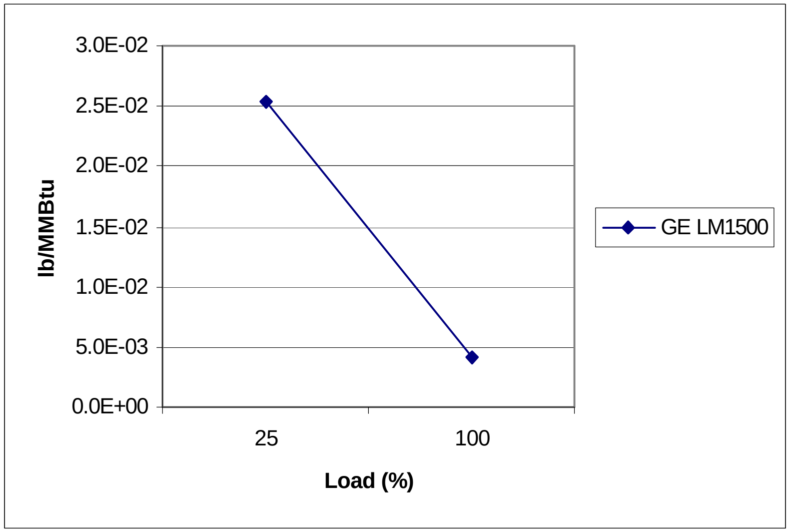
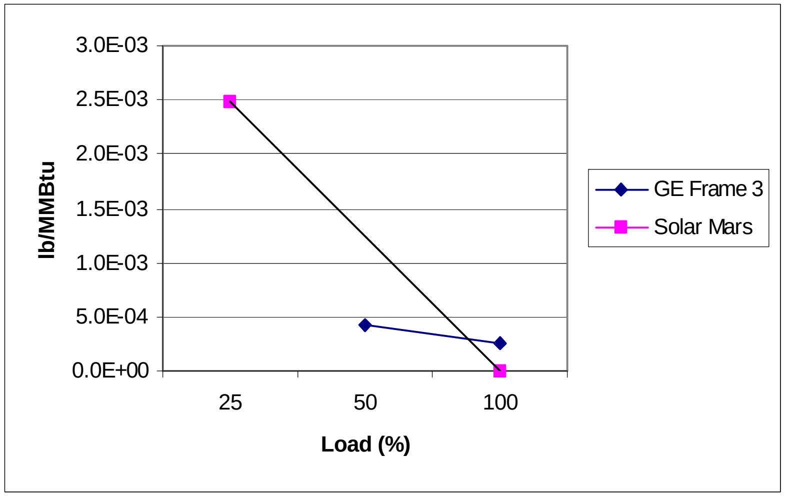
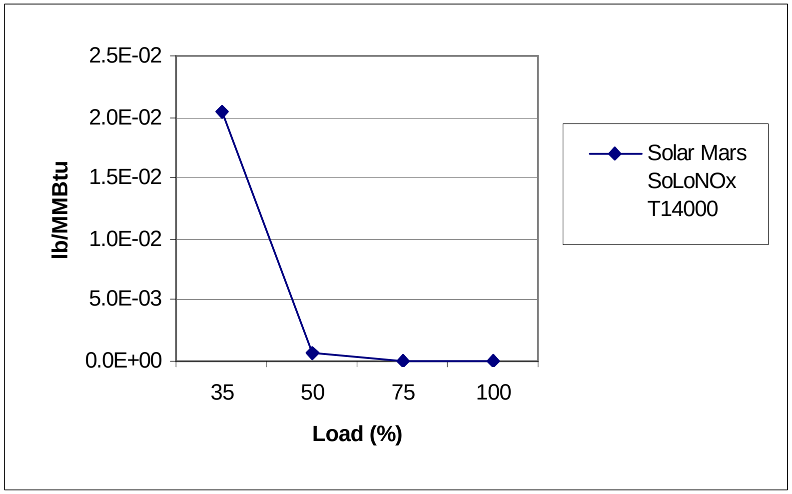


Figure 6B. Formaldehyde Emissions vs. Load (GRI/EPRI tests)









The Committee further believes that an operator would rather operate turbines at as high a load as possible. For example, an operator would rather operate one turbine at 100 percent load and shut down two turbines rather than operate three turbines at 33 percent load. There is a strong economic incentive for an operator to practice efficient load management. In summary, lower loads probably increase HAP emissions, but at those conditions the turbine is operating as well as possible, and the operator has no control in reducing HAP emissions.

Figure 7 shows Cr(VI) emissions versus load. Again there is no logical correlation or discernible relationship. The Committee believes that such metals are randomly introduced in the fuel, air, lube oil, and to a small but unknown degree, blade erosion.

3. Fuel Type vs. HAPs:

Benzene, toluene and xylene were plotted in Figures 8A, 8B, and 8C for natural gas, landfill gas and No. 2 fuel oil. The HAP data spread for the various fuels is significant. The Committee concluded that a MACT floor determination based solely on the use of fuel cannot be supported. The Committee is of the opinion, however, that separate subcategories may still be justified for above the floor analysis based on other reasons, e.g., negative impact of a fuel on control technology.

4. Operating Practices vs. HAPs:

The Committee examined operating practices in detail to ascertain their impact on HAPs formation/abatement. A separate paper, Appendix A, addresses these issues with respect to turbines and is attached. The Committee concluded that, since most operating variables are pre-determined by the manufacturer, there are no discernible, additional practices that would reduce HAPs.

5. Combustor Design vs. HAPs:

The Committee examined the relationship of combustor design, i.e., heavy duty industrial versus aeroderivatives for benzene and formaldehyde and could not draw a clear conclusion or identify a relationship. The Committee also concluded that since there was only one data point on lean, pre-mix combustors, no relationship could be established. Also, since this design (i.e., lean, pre-mix) will increasingly find application in the U.S. because of its low criteria emissions at full load, the Committee noted that this design should be included in the recommended test plan.

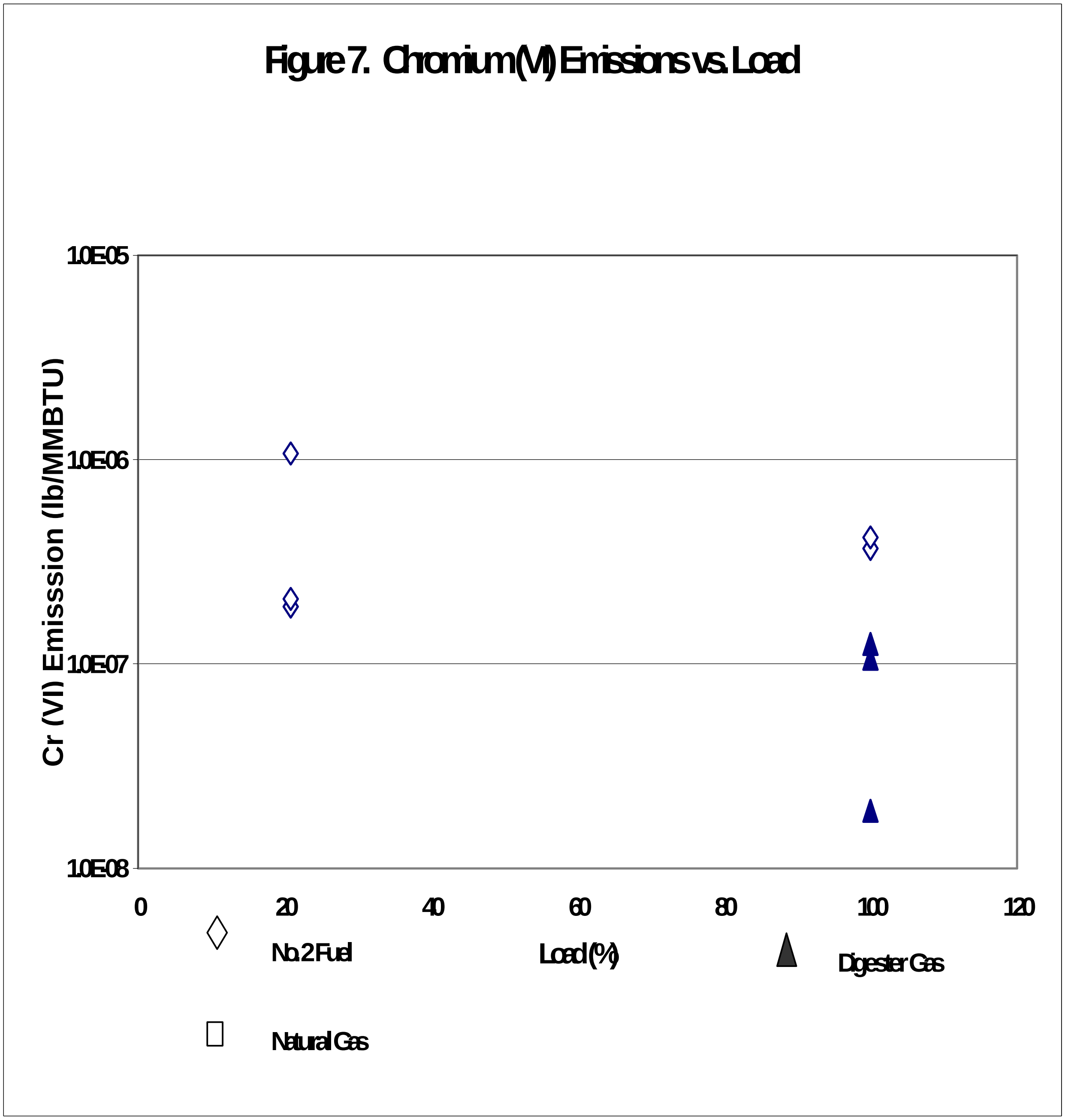


Figure 7. Chromium (VI) Emissions vs. Load
Cr (VI) Emisssion (lb/MMBTU)
1.0E-05
1.0E-06
1.0E-07
1.0E-08
0
20
40
60
80
100
120
Load (%)
No. 2 Fuel
Digester Gas
Natural Gas

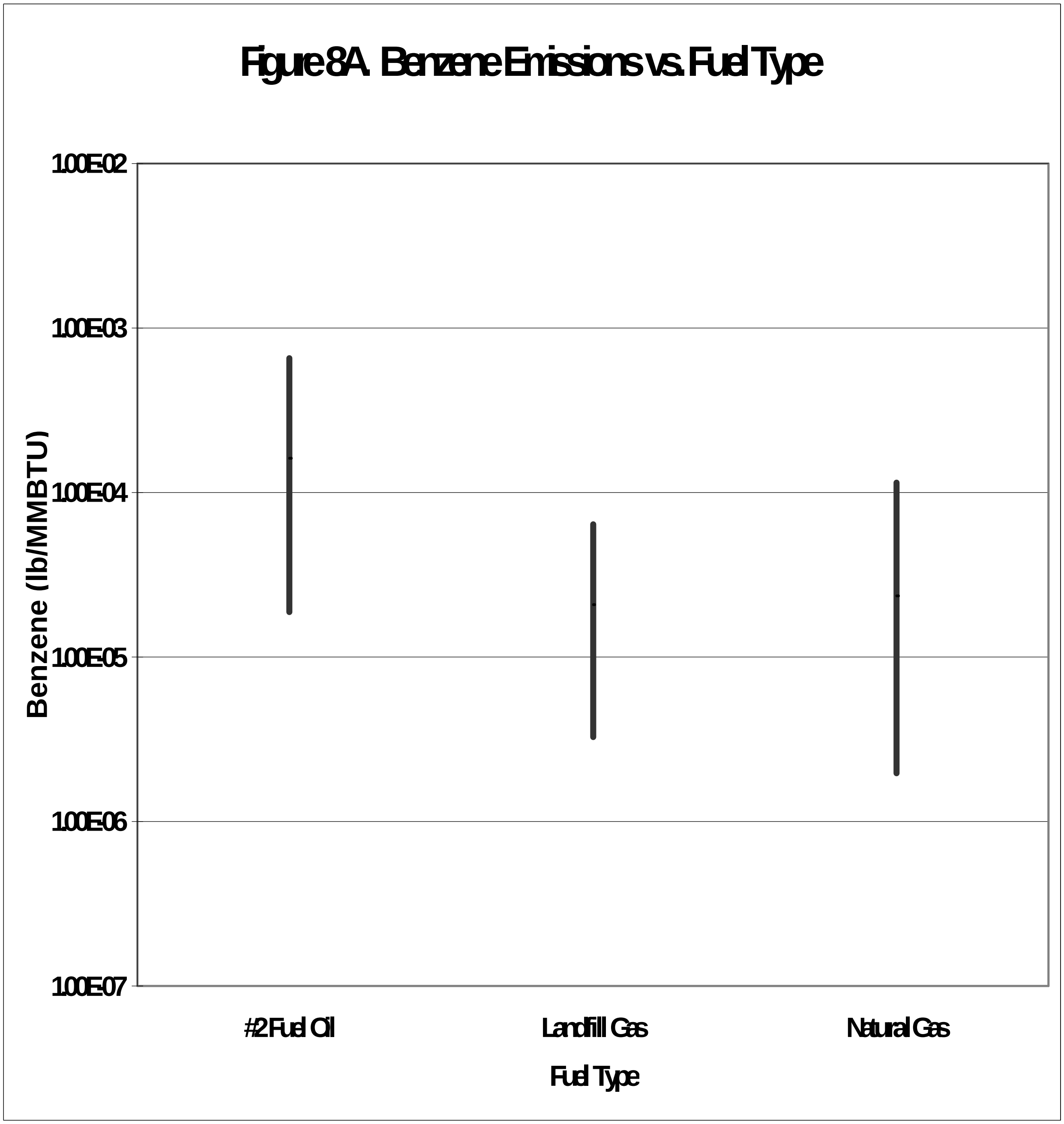


Figure 8A. Benzene Emissions vs. Fuel Type
1.00E-02
1.00E-03
1.00E-04
1.00E-05
1.00E-06
1.00E-07
Benzene (lb/MMBTU)
#2 Fuel Oil
Landfill Gas
Natural Gas
Fuel Type

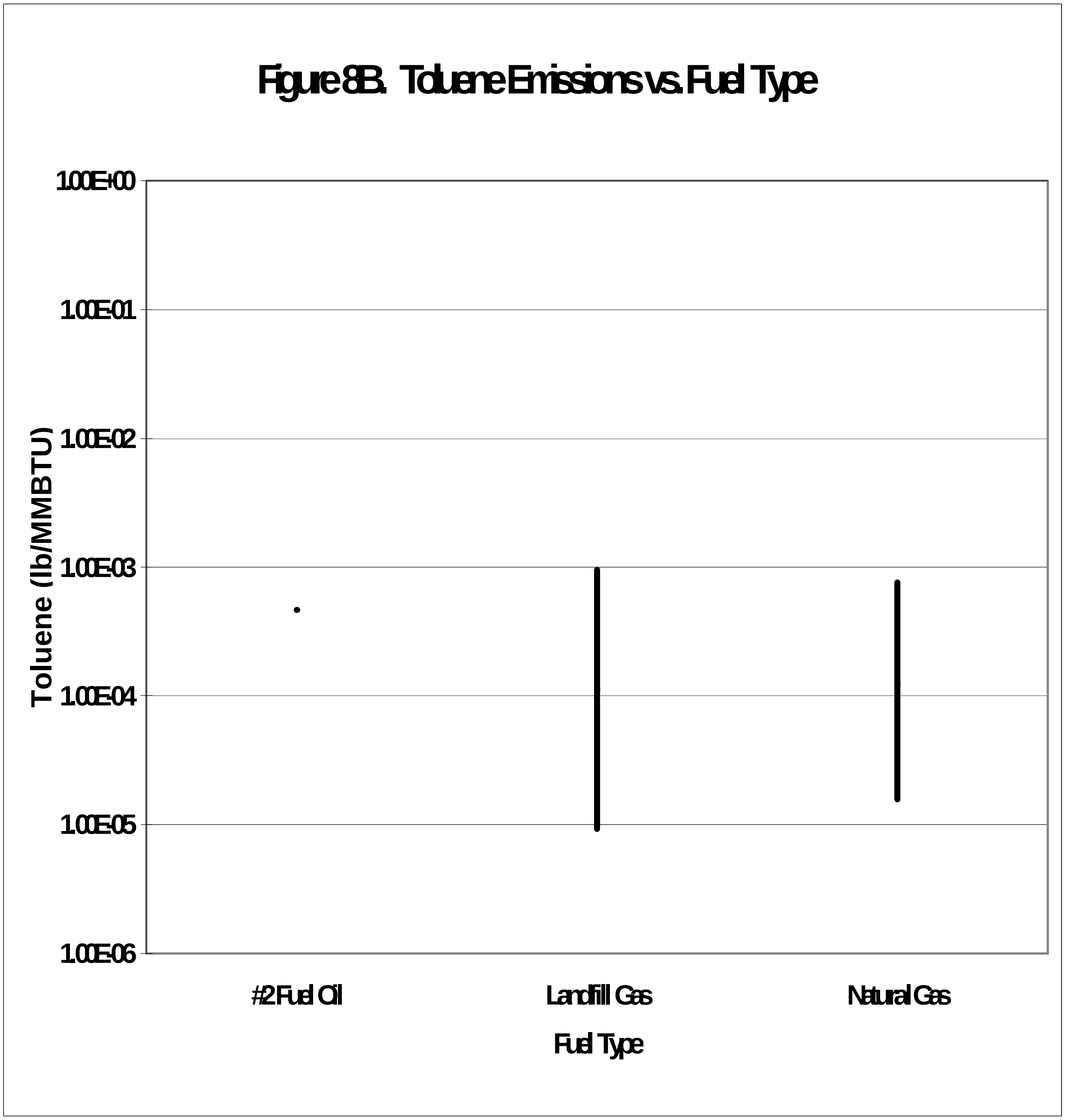


Figure 8B. Toluene Emissions vs. Fuel Type
1.00E+00
1.00E-01
1.00E-02
1.00E-03
1.00E-04
1.00E-05
1.00E-06
Toluene (lb/MMBTU)
#2 Fuel Oil
Landfill Gas
Natural Gas
Fuel Type

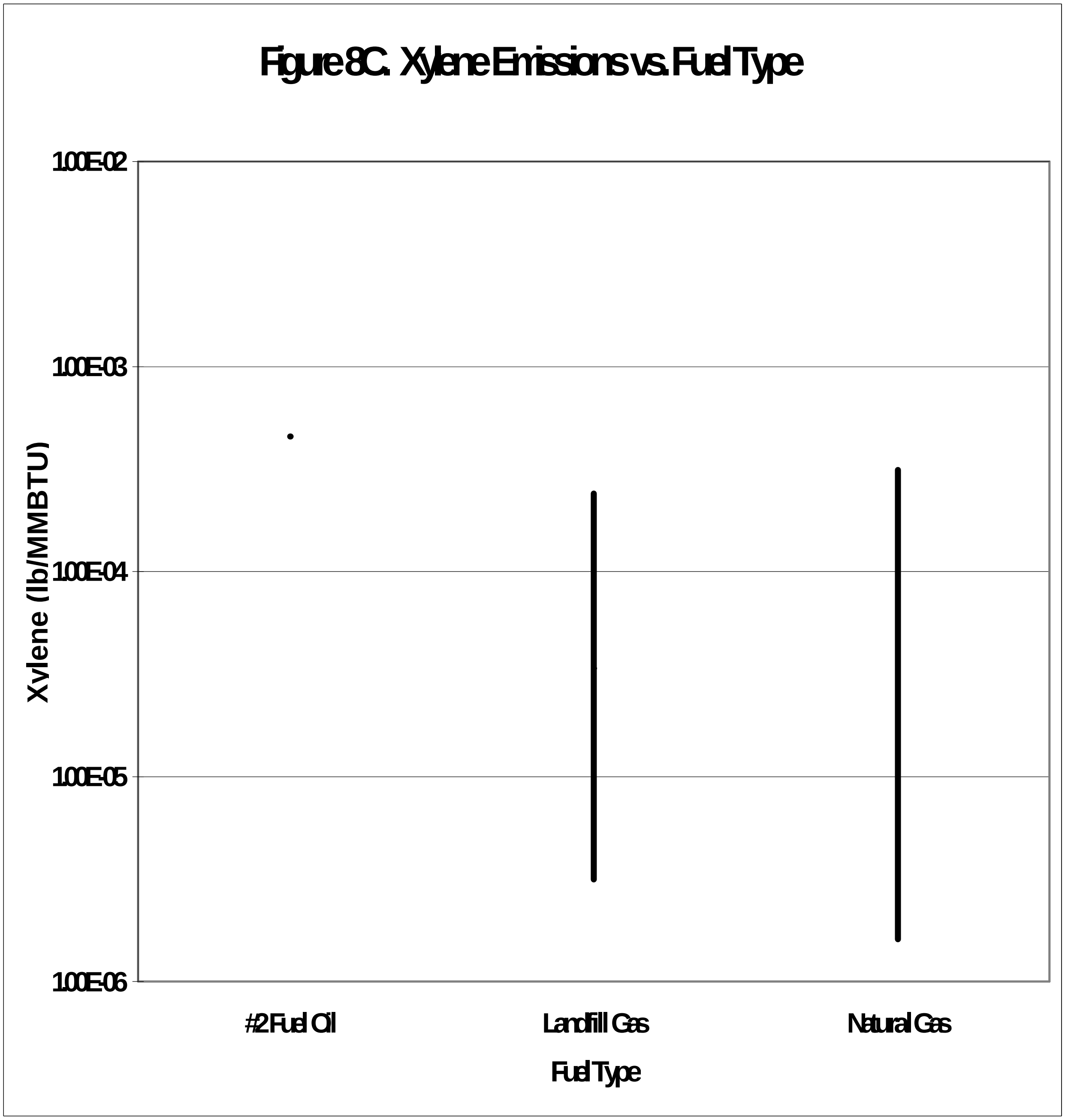


Figure 8C. Xylene Emissions vs. Fuel Type
1.00E-02
1.00E-03
1.00E-04
1.00E-05
1.00E-06
Xylene (lb/MMBTU)
#2 Fuel Oil
Landfill Gas
Natural Gas
Fuel Type

State Regulations/Permits

Another approach that was considered in setting the potential MACT floor was the utilization of existing state regulations and permits. No state regulations exist for HAP emission limits from combustion turbines. HAP emissions estimates, not limitations, from stationary combustion turbines exist for the State of California only. State permits of HAP emissions were also reviewed for existing turbines. To find out if there were any state permits that regulate HAPs from turbines, the current, historical, and transient databases of the EPA RACT/BACT Clearinghouse were searched. The search turned up one facility with an emission limit for benzene. This facility is in the State of Alabama. It was determined that one state permit for one HAP is not enough to guide the MACT floor determination process. Therefore, the MACT floor cannot be based on any existing state regulations and permits for combustion turbines.

Conclusions

- There is no relationship that can be identified, with the exception of operation at partial load, between HAP emissions and any other turbine variable such as size, fuel type, operating and maintenance practices, use of any type of emission control technique or device, or combustor design. As a result, the apparent difference in HAP emissions which may exist among combustion turbines is due to inherent variability among turbines, not to specific differences in "performance." It is not possible, therefore, to identify a subset of existing combustion turbines which represents the "... best performing 12 percent ...".

- There are no data on emission reduction technologies or add-on control devices that are known to reduce HAP emissions in the EPA emission database. Add-on exhaust control devices installed for any reason that may reduce HAP emissions are present in slightly more than two percent of the existing turbine population based on vendor estimates. Therefore it is not possible to develop a MACT floor for existing combustion turbines based on these potential technologies.

- There are no practical operating practices that can be recommended that will impact HAP emissions from combustion turbines short of operating as close to maximum load as possible.

- Operation at partial load appears to increase HAP emissions. However, operation at partial load is necessary for load following applications.

APPENDIX A
OPERATING PRACTICES / TRAINING PROGRAMS

Objective

This analysis seeks to determine if specific operating practices and/or operator training programs have the potential to reduce HAP emissions from combustion turbines and to propose such operating practices/training programs, if any, for inclusion in the MACT standard for combustion turbines. Rather than discussing generalities or specific capital features such as adding recuperators, the focus will be on specific operating practices/training programs that can be implemented on combustion turbines to reduce HAP emissions.

Background

Proper maintenance and upkeep of a turbine will help ensure optimum performance over its lifetime. Manufacturers recommend operation and maintenance (O&M) procedures to establish the parameters under which their warranty for the equipment would be valid. They are designed to avoid equipment damage rather than to minimize emissions, recognizing however, that proper maintenance will usually maintain good efficiency or improve poor efficiency. These O&M procedures contain sections on preventive maintenance and corrective maintenance. While owners/operators may customize these manufacturer-recommended O&M procedures due to updated information or to suit site-specific conditions, such as extreme ambient temperature fluctuations or remote automated operations, ignoring or neglecting service/maintenance procedures will have an adverse impact on the performance and life of the turbine.

Recognizing its importance to the long-term well-being of the equipment and to resulting air emissions, some state and local air permits contain language:

(1) specifying that O&M manuals need to be developed, maintained on-site or at the nearest manned site and made available for inspection upon request; and

(2) requiring periodic certifications, under Title V, that the O&M procedures are being followed and kept current.

The EPA database contains emissions from a variety of combustion turbines. Emissions vary by one to two orders of magnitude, with no discernible pattern or reason. There is no process or operating information in the database that seems to be able to explain the inherent variation or its cause. HAP emissions are either products of incomplete combustion (PICs) or they may result from other sources. The combustion characteristics and degree of completeness of combustion are determined by several factors including type of combustor, firing temperature, residence time, stoichiometry, combustion chamber configuration, and whether water/steam injection is used for NOx control.

Turbine Applications

Turbines are used in the utility power generation industry, cogeneration applications, industrial mechanical-drive and pipeline applications, offshore and marine applications. Cogeneration applications are generally base-load applications, while utility power generation will include base-load and peaking units. Industrial mechanical-drive and pipeline applications are generally load-following applications, where the output load sends signals to the control system to regulate the fuel accordingly.

Design Aspects

Combustion turbines operate on the principle of volumetric expansion of air at very high rotational speeds. The expansion of heated air occurs through and across stationary nozzles and moving blades, machined with great precision. The very high speeds and close tolerances of turbo-machinery are directly related to efficiency. Speeds are so high in fact, that turbines are heavily automated with both control, safety and diagnostic features that sense and respond much faster than a human being might. Combustion turbines have relatively few contacting parts (compared to a reciprocating engine, for example) and are highly reliable.

The turbine design is based on a thermodynamic cycle and an aerodynamic flow path. This establishes the point of maximum efficiency. A turbine's performance can then be represented by a set of performance curves, relating output power to ambient temperature, fuel flow, exhaust mass flow, exhaust temperature, and inlet and exhaust duct pressure losses. An altitude correction factor will account for operation at elevations other than sea-level. Once these parameters are established by the manufacturer's design, the unit's control system package regulates operation along these curves, with very little active operator involvement. Since operation of a turbine outside of the control system defined boundaries could lead to premature mechanical failures, turbine manufacturers have adopted control system design practices that assure very high reliability for the controls.

Turbine Operation

Although there are design variations, the start sequence generally starts with the pre-lube cycle. Following that the starter is engaged and rotation of the turbine begins. After attaining the minimum speed and upon completion of the purge cycle to remove any fumes that might cause premature explosions and that can impede ignition, ignition occurs. As fuel is increased, the turbine speed increases at an automatically controlled rate and at a specified design speed, the starter will be disengaged. The unit then accelerates to design speed and becomes self-sustaining. Any malfunction in the system will cause the control system to stop the fuel feed, thereby shutting down the system. Speed or power is then changed by signals to the throttle valve through a governor or actuator.

During operation, the unit control system continuously maintains cycle parameters within predetermined constraints set by the manufacturer as part of the turbine design. The shutdown procedure is initiated when the run circuits are de-energized and the fuel feed is reduced at a predetermined rate and stopped, thereby causing the turbine to coast to a stop after a cool-down cycle. In some applications, such as interstate pipelines, the start/shutdown sequence is automated and is generally initiated remotely from a central control room for the entire system of turbines along the pipeline. Once a unit comes on line, the automated control system takes over and operates the unit at design load with minimal involvement and oversight from manual systems.

In all the applications, the unit control system generally regulates fuel throttle to maintain acceptable firing temperature and speed follows. The control system provides warning and/or automatic shutdown signals in the event of an undesirable operating condition. Under normal operating conditions, there is little operator involvement in the operation of the combustion turbine.

Operating Practices

Under the topic of operating practices, the following were considered:

(1) operating practices – documentation of operating procedures, including startup, shutdown and malfunction plans, and maintenance of operating logs;

(2) maintenance knowledge – operator training;

(3) maintenance practices – documentation of maintenance procedures; and

(4) monitoring fuel quality.

1. Operating Practices:

As stated earlier, some state and local air permits specify that O&M manuals be followed and require that such manuals be kept on-site and made available for inspection. Recognizing the inherent design variations and the influence of site-specific conditions, the owner/operator is given the flexibility in some state permits to develop site and unit-specific O&M procedures. Other regulatory requirements also specify the use and maintenance of documented operating procedures. The MACT standard General Provisions (40 CFR Part 63) specify the use of startup/shutdown procedures to help maintain compliance with a MACT standard. States such as Texas, Oregon, Washington and Idaho, specify the use of written startup/shutdown procedures to minimize emissions if there is the potential for excess emissions during such transient conditions. The requirement to maintain logs are specified by the monitoring, record keeping and reporting requirements under the 40 CFR Part 70 (Title V operating permit) regulation. (Most facilities with combustion turbines are probably major sources of criteria pollutants and hence are subject to Title V requirements.) Other regulatory agencies, such as the Department of Transportation (DOT), specify detailed written operating and maintenance procedures for interstate pipelines. These are pre-existing requirements and new, additional regulation is not necessary for operators to follow an O&M procedure or plan.

O&M procedures are established by manufacturers and followed by owner/operators to improve the reliability of the turbine and avoid equipment damage. There is no evidence that following such procedures will result in a reduction of HAP emissions which depend on the degree or completeness of combustion, combustion characteristics and the design parameters. The Committee believes that these O&M practices are followed by turbines in the EPA databases. Furthermore, there is no evidence to suggest that HAP emissions from the highest-emitting unit in the EPA emissions database was caused by improper O&M practices or that the HAPs can be reduced by specifying a more detailed or exhaustive/comprehensive O&M procedure for that unit.

2. Maintenance Knowledge / Operator Training

Combustion turbines are a sophisticated reliable technology, designed for remote, automated operations with minimal operator involvement for routine operations. Unlike process heaters, boilers and IC engines, there is no provision for the turbine operator to change operating parameters, such as adjusting the air to fuel ratio or the spark timing. Once the manufacturer commissions a turbine in the field, the operator makes no changes to key design operating parameters. The manufacturer may inspect and confirm the key design parameters at the time of a turbine overhaul, but the operator does not make design changes on his/her own initiative and does not seek to operate the unit outside the design specifications.

Operators, as part of their internal O&M procedures, also specify training and/or qualification requirements from a performance, reliability, service/maintenance, manufacturers warranty requirement, and a safety perspective. Established company training programs also specify the ground-rules by which an apprentice advances to a mechanic or a technician level, a prerequisite to operating multi-million dollar equipment. Other programs, such as OSHA and Process Safety Management (PSM), address operator training programs and requirements. For example, PSM specifically is triggered if more than 10,000 pounds of fuel in a covered process is stored on site. The risk management program under section 112(r) of the CAAA establishes thresholds for certain chemicals, and specifies training on accident prevention and release response procedures. Owners and operators in the spirit of efficient training and saving resources will recognize the advantage of combining mandatory PSM training with general operator training. Inter-state pipelines are subject to DOT regulations that specify prescriptive operator training requirements. New, additional regulatory language in a combustion turbine MACT is therefore not necessary to prompt turbine owner/operators to protect their significant capital investment by ensuring that their operators are properly and adequately trained.

As was the case with operating practices, there is no evidence to suggest that HAP emissions from the highest-emitting unit in the ICCR database were caused by improper training programs or that the HAPs could be reduced by specifying more operator training. Design parameters establish the emissions profile and operator training programs cannot change the design emissions profile. The inherent emissions variability, caused by design variations, cannot be avoided or eliminated by operator training programs.

3. Maintenance Practices:

The discussion of O&M practices in the Operating Practices section deals with maintenance practices also. Owner/operators follow manufacturer-recommended or customized (to account for unit- and site-specific characteristics) O&M procedures and practices to ensure reliable performance of their turbines. Given the sizable capital investment, the owner/operators have a vested business interest in the longevity and continued performance of the turbine. Additionally, air permits generally specify that the equipment be operated and maintained properly to ensure its proper functioning.

Again, there is no evidence to suggest that HAP emissions from the highest-emitting unit in the EPA database were caused by improper maintenance procedures. It is also not evident that specifying additional maintenance procedures would have reduced the HAP emissions. The inherent emissions variability is a function of design and combustion characteristics, and does not appear to be a function of maintenance procedures.

4. Fuel Quality:

The fuel quality, whether in terms of superheat or dewpoint for gaseous fuels, and/or the presence of entrained impurities, will be specified by the manufacturer and continued use of fuel outside manufacturer's specifications will likely result in unit malfunction and/or degradation of performance. Some regulations, such as the fuel sulfur requirement in the NSPS regulation, specify fuel constituent limits. The owner/operator's vested interest in protecting his/her capital investment will dictate that particular attention will be paid to the fuel quality and any resulting lack-of-performance issues.

Manufacturers generally provide fuel specifications for liquid fuels, especially with regards to metals. Knock-out pots and filters are used in some cases to remove entrained liquids and other impurities. Both gas-fired and liquid-fired combustion turbines showed high variability of HAP emissions, but fuel quality does not explain the inherent emissions variability seen in the data.

Some other parameters with the potential to affect turbine emissions are considered below.

Air to Fuel Ratio: The air-to-fuel ratio, a design criterion, is specified by the performance curves referred to earlier and any change to the relationship designed by the manufacturer is not possible without significant change to the hardware and control system. A delicate balance of air to fuel ratio has to be maintained to sustain proper combustion. Manufacturers are now using staged combustion and/or variable geometry concepts to achieve stable combustion while minimizing criteria pollutants. Variable geometry combined with pre-mixing air and fuel is now being used to optimize combustion conditions for low emissions, but this is not a feature that an owner/operator can modify at his/her discretion. Inlet guide vane (IGV) settings (controlling the total air flow to maintain air/fuel ratio at the design condition over an extended range) are generally established by the manufacturer upon installation, and owner/operators do not modify these settings after startup on their own. Not only is inlet air used for combustion, but a major portion of the air swallowed by the turbine is also used for cooling purposes and altering the proportion beyond design criteria could have negative impacts on internal metallurgy (e.g., creep crack, oxidation, etc.). The data in the emissions database does not show a direct relationship between HAP emissions and air to fuel ratios. Since air to fuel ratios are set by design considerations, with no provision for operator modification, this is not a practical operating technique to control HAP emissions from combustion turbines.

Water/Steam and Ammonia Injection: Where there is water/steam or ammonia injection, air permits require that the injection rate be monitored. The Part 60 NSPS regulation also requires continuous monitoring for such units. This is a pre-existing requirement and therefore does not need to be added to a MACT regulation.

Combustor Temperature Monitoring: For certain turbine types, (e.g., can annular combustor types), monitoring of the combustor temperature relationships will provide an indication of proper operation. Any clogging or abnormality in the fuel feed system would result in an irregular temperature profile and lower power output. On many turbines of these types, the unit control package monitors the temperature profile and triggers system alarms or corrective actions (e.g., automatic control system correction in fuel flow split between the primary and secondary stages in a lean pre-mix combustor) in the event of abnormalities or deviations outside pre-set ranges. Even without monitoring the temperature profile, which is not the case, reductions in power output will alert and flag the operator to a potential abnormality or malfunction within the system. Higher fuel consumption to generate the same power output will also prompt corrective action.

Conclusion

Examination of the database did not reveal specific O&M practices or operator training programs that could explain or remove the inherent emissions variability. It was not possible to identify any viable specific operating practice or training program to reduce HAP emissions across the various fuels, makes, models, and sizes of combustion turbines. It does not appear that any specific operating practice or training program would eliminate the inherent emission variation among the different makes and models and cause a general reduction in the level of HAP emissions. The emissions variability in the database indicates that HAP emissions are a function of equipment and design constraints and limitations, and not a function of O&M practices.

O&M procedures are widely used by industry and by the manufacturers to formalize operation and maintenance activities. Additionally, programs such as OSHA, PSM and state/local air permits establish O&M practices and operator training requirements. Given the pre-existing programs, new or additional requirements are not necessary to ensure proper operation and maintenance of turbines.

O&M procedures established by manufacturers and followed by owner/operators are designed to improve the reliability of the turbine and avoid equipment damage. There is no evidence that following such procedures will result in a reduction of HAP emissions, which instead depend on the degree or completeness of combustion, combustion characteristics and the design parameters. There is no evidence to suggest that HAP emissions from the highest-emitting unit in the EPA database was caused by improper O&M practices, or that the HAPs could have been reduced by specifying a more detailed or exhaustive/comprehensive O&M procedure for that unit.

APPENDIX B

HAPS and Criteria Pollutant Source Test Checklist

HAPS and Criteria Pollutant Source Test Checklist	Source Test Report #____ Date__________	Source Test Report #____ Date__________
BASIC TURBINE INFORMATION		
Manufacturer		
Model #		
Rating (BHP or MW)		
Operating Cycle (Simple, Regenerative, etc.)		
FUEL DESCRIPTION		
Fuel Name(s)		
Fuel Analysis Summary		
Flowrate (or BTU/H, if available)		
OPERATING CONDITIONS		
Load (during test)		
Water or Steam Injection and/or Ammonia Mass Flowrate		
Firing Temperature or Turbine Inlet Temperature		
AMBIENT CONDITIONS		
Temperature		
Relative Humidity		
Barometric Pressure		
Altitude		
EXHAUST INFORMATION		
Temperature		
Flowrate (F-Factor or Measured)		
EMISSIONS TEST		
*Criteria Pollutants		
HAPS		
Oxygen or CO_2		
Moisture		
Averaging Time		
METHODS USED		
CARB		
EPA		
Other ______________________		
QUALITY CONTROL DOCUMENTATION		
Calibration of Instruments		
Specialty Gases		
CEMs		
Dry Gas Meters		
MISCELLANEOUS		
Limits of Detection Reporting		
Supplemental Firing Details		
YOUR PERSONAL OPINION AS TO REPORT QUALITY		

*Attach separate sheet if necessary (ppb, ppm, lb per hr as measured and corrected to 15% O_2 or 12% CO_2, etc., dry).

APPENDIX C

This memorandum provides a short description of the development of the emissions database for turbines, including assumptions used in the underlying calculations.

Development of the Emissions Database

The emission test reports were first carefully reviewed and summarized. Facility name, location, testing company, date of testing, make and model of turbine, manufacturer rating (and units), load, fuel type, application and control device (for emissions) were entered in a table named "Facilities." Pollutant name, sampling method, concentrations and units, detection limits and units, % oxygen, fuel factors, exhaust gas flow rates, stack temperature, fuel heating value and flow rate, % humidity, standard temperature, and pollutant molecular weight were entered in a table named "Test Data." Emission rates (lb/hr) and emission factors (lb/MMBtu) were also entered in that table for comparison with the emissions calculated in the database using the pollutant concentrations for each test run.

Test reports included in the database were identified using the following scheme: numbers from 1 to 99 were assigned to tests containing only hazardous air pollutants (HAPs), and numbers greater than 100 were allocated for tests with only criteria pollutants or with both HAPs and criteria pollutants. Exceptions are the reports numbered 10 and 15. These test reports contain both HAPs and criteria pollutant test results. They are numbered as HAPs-only type reports because criteria pollutant data were identified in these reports after the first version of the database was posted on the TTN. Test reports containing more than one turbine, multiple load conditions, different fuels, control device inlet and outlet samples (criteria pollutant data only), or more than three sampling runs were assigned the same initial number followed by an extension (for example, 1.1 or 1.1.1).

Some of the test reports in the database include an "x" symbol at the end of the test report number (e.g., test report 8x). The "x" symbol indicates that the test report does not meet the acceptance criteria. The data from these test reports are included in the database for informational purposes only.

Construction of database reports (i.e., summaries of relevant data) required the complete separation of tests with HAPs-only data from tests with only criteria pollutant data and tests with both HAPs and criteria pollutant data. The "Test Data" table was consequently divided into three tables: "Test Data - HAPs," containing all HAP data in the Test Data table; "Test Data - Criteria Pollutants," containing all criteria pollutant data in the Test Data table, and "Test Data - HAPs + Criteria," containing the tests that include data for both HAPs and criteria pollutants.

In the report section, a set of 6 different reports was built for each of the test data tables discussed above. These reports provide information about pollutant concentrations (corrected to

15% O_2) and emissions in units of lb/hr, lb/MMBtu, and lb/MW-hr. Individual sets of reports were also developed for test summaries and pollutant summaries.

Treatment of non-detected or non-reported concentrations

Many pollutants, especially HAPs, were not detected in some or all of the sampling runs collected during a test. In these cases, concentrations were entered in the database as "ND." Although the test reports identified those pollutants not detected for a given testing run, the detection limit (DL) values were not always provided (i.e., ND was reported rather than a detection limit concentration). Often, review of the lab report and some additional calculations were necessary to determine the DL concentration. For example, in the case of formaldehyde, detection limits were usually given in micrograms or micrograms per milliliter in the lab report. Estimation of the DL in the same units as the test data (e.g., ppb) involved the use of the sample volume collected during the test and additional unit conversions (for example, micrograms/cubic meter to ppb).

Unfortunately, the DL could not always be found or calculated based on the laboratory report. Whenever a pollutant was not detected in all three runs and the DL could not be determined, the pollutant was removed from the database. This procedure was used for report ID #1 for benzene and chromium (VI). Also, due to the calculations discussed above, two or three different DLs (one per testing run) were determined for the same pollutant in some tests. The protocol followed in these cases was to take the highest DL value.

In some tests, only one or two runs were conducted, or runs were eliminated during test report preparation due to sampling problems encountered during the test. Missing runs were entered as NR (not reported) in the database. Other parameters missing from the test reports, such as exhaust gas flow rates, were also entered in the database as NR.

The acronym NA sometimes appears in the DL field. This acronym is used in those cases when a pollutant was measured above the detection limit in all of the testing runs but a detection limit value was not reported in the test report.

Equations

Using raw test data (i.e., lab-reported pollutant concentrations and stack test parameters), calculations were performed to estimate emissions in lb/hr, lb/MW-hr and lb/MMBtu. Modules, small programs written in Visual Basic code, were built to perform the calculations. There are various modules in the emissions database that perform different tasks, but only the main modules are described in this memorandum.

The equations used in the modules were taken from EPA sampling methods 19 and 20 in 40 CFR Part 60, Appendix A. For example, for the correction of the dry pollutant concentration to 15% O_2, Equation 20-4 from EPA method 20 is used:

$$C_{adj} = C_d \times \frac{20.9-15}{20.9-\%O_2}$$

where $\%O_2$ refers to the reported oxygen level during the testing and C_d to the pollutant dry concentration in ppb.

For the calculation of emission rates in lb/hr, lb/MW-hr, and lb/MMBtu, the following equations were used :

1. Pounds per hour:

When the concentration of pollutant is given in ppb :

$$M(lb/hr) = C_{ppb} \times Q \times 60 \times \frac{MW}{T_{std}+460} \times 1.369x10^{-9}$$

where C_{ppb} is the dry concentration of pollutant in ppb; Q is the exhaust gas flow rate in dry standard cubic feet per minute; 60 is the conversion factor from minutes to hours; MW is the pollutant molecular weight (in lb/lb-mol); T_{std} is the standard temperature in degrees Fahrenheit used in the test report; 460 is the conversion factor from degrees Fahrenheit to degrees Rankine; and $1.369x10^{-9}$ is the conversion factor from ppb to pounds per cubic feet. The conversion factor from ppb to pounds per cubic feet was derived from 40 CFR, App. A, Meth. 20, page 1026.

When the concentration of a pollutant is given in units other than ppb or ppm, the equation is :

$$M(lb/hr) = C_p \times Q \times 60 \times A$$

where C_p is the concentration of pollutant in micrograms per dry cubic feet (ug/dscf), micrograms per dry cubic meter (ug/dscm), grams per dry cubic feet (g/dscf) or grams per dry cubic meter (g/dscm). For particulate matter, concentrations are in grains per dry cubic feet (gr/dscf), grains per dry cubic meter (gr/dscm), micrograins per dry cubic feet (ugr/dscf) and micrograins per dry cubic meter (ugr/dscm). Q is the exhaust gas flow rate in dry standard cubic feet per minute; 60 is the conversion factor from minutes to hours; and A is a conversion factor from the given units to lb/dscf.

The values for A for the different units are:

1.1 For ug/dscf, $A = 2.205x10^{-8}$

1.2 For ug/dscm, A = 6.24×10^{-10}
1.3 For g/dscf and g/dscm, multiplying 1.1 and 1.2 by 1×10^{-6}
1.4 For ugr/dscf, A = 1.43×10^{-10}.
1.5 For ugr/dscm, A = 4.043×10^{-12}.
1.6 For gr/dscf and gr/dscm, multiplying 1.4 and 1.5 by 1×10^{-6}

2. Pounds per megawatt-hour:

The emission factor is calculated by dividing the emissions rate in lb/hr by the turbine rating during the test. The manufacturer rating and the test load are necessary data for this calculation. When load was not available, it was assumed to be 100%. The equation is :

$$M(lb/MW\text{-}hr) = \frac{M(lb/hr)}{R \times \frac{L}{100}}$$

where M(lb/hr) is the emission rate in lb/hr; R is the manufacturer rating for the turbine in MW; and L is the turbine testing load in %.

3. Pounds per million Btu:

The equation is :

$$M(lb/MMBtu) = C_p \times F \times \frac{20.9}{20.9 - \%O_2} \times B \times \frac{MW}{T_{std} + 460}$$

where C_p is the dry concentration of pollutant in any of the units already described for the calculation of emission factors (1.1 - 1.6); F is the fuel factor in dry standard cubic feet per minute per million Btu; the fraction $20.9/(20.9\text{-}\%O_2)$ is an oxygen correction factor; and B is the conversion factor corresponding to the units in which the pollutant concentration is reported (see the units described in 1.1 - 1.6). The fraction $MW/(T_{std}+460)$ is a conversion factor used only when the pollutant concentration was provided in ppb.

When the fuel factor or standard temperature was not available, defaults were used. These defaults are discussed in next section.

A sample of the modules used for the calculations is provided in Appendix C-1.

Defaults and Assumptions

For the estimation of emission factors from the concentrations given in ppb, gaseous pollutants were assumed to have ideal gas behavior, so that the volume occupied by an ideal gas (22.4 liters/mol) could be used for calculation of a conversion factor.

Not all of the reports contained the necessary information required for the calculation of emission factors. Important parameters are concentrations, units, detection limits, oxygen levels, exhaust gas flow rates, fuel factors, standard temperatures and molecular weights. In most cases, fuel factors and standard temperatures were missing. In some cases, exhaust gas flow rates were not provided in the report. Lack of gas flow rates still allows for the calculation of emission factors in pounds per million Btu. Consequently, tests lacking exhaust gas flow rates were kept in the database, but the emissions in pound per hour are shown as NR.

For non-methane hydrocarbons (NMHC) and total hydrocarbons (THC), a molecular weight of 16 (as methane) was assumed. Test reports in the database indicated a molecular weight of 16 for THC and, in most cases, for NMHC. However, in some test reports, the molecular weight chosen to report emission factors for NMHC was the molecular weight of hexane.

Fields with NR for fuel factors and standard temperatures were filled with default values based on Table 19-1 in 40 CFR Part 60, Appendix A. A default standard temperature of 68°F was used. This standard temperature was selected because EPA sampling methods rely on this value.

As discussed earlier, some pollutants were not detected in one or more of the sampling runs conducted during a test. In these cases, the detection limit was used in the emission calculations. Reports generated in the emissions database use a "<" sign in front of the sampling run concentration, as well as the average concentration calculated for the three runs, to indicate when a pollutant was not detected in one or more of the runs. When a pollutant was not detected in all three runs, a "<<" sign is shown in front of the average concentration presented in the database reports. The DL value was used in calculating the average concentration when a pollutant was not detected in one or more of the runs.

Appendix C-1

Sample of modules used in the database

The modules shown here are the modules for the calculation of emission factors in pounds per million Btu (Module Convert) and the module that handles the criteria for the use of detection limits (Module NonDetect).

1. Module for the calculation of emission factors in pounds per million Btu

1.1 Declaring the function that will perform the calculations and return the result to the query. The parameters r, s, t, u, v, w, z refer to concentration units (r), fuel factor (s), molecular weight (t), standard temperature (u), % oxygen (v), concentration (w), and a parameter (z, set to three in the database) used to limit the number of significant digits (utilizing another module) in the result.

Function lbMMBtu (r, s, t, u, v, w, x, y, z)

1.2 Estimating the emission factor to return to the query that is calling this module. First the module identifies the units (r=ppb), then it makes sure that there are values in all necessary fields and finally performs the calculation. SigDig_ is calling another module that will perform the reduction of the result to a given number (z) of significant digits. Val calls for the numerical value of the field being processed.

```
If ((r = "ppb") And Not (s = "NR" Or t = "NR" Or v = "NR" Or w = "NR")) Then
        lbMMBtu = CStr(SigDig_((Val(s) * Val(t) * (.00000000137 / (Val(u) + 460)) *
 (20.9 / (20.9 - Val(v))) * Val(w)), z))

ElseIf ((r = "ug/dscm") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
       lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .0283 * .000000002204 *
      (20.9 / (20.9 - Val(v)))), z))

ElseIf ((r = "ug/dscf") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
       lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .000000002204 *
      (20.9 / (20.9 - Val(v)))), z))

ElseIf ((r = "gr/dscf") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
       lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * (20.9 / (20.9 - Val(v))) / 7000), z))

ElseIf ((r = "ugr/dscm") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
        lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .0283 * (20.9 / (20.9 - Val(v))) *
 0.000001 / 7000), z))
```

```
ElseIf ((r = "gr/dscm") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
        lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .0283 * (20.9 / (20.9 - Val(v))) /
        7000), z))
```

1.3 In any other case (units not recognized or necessary parameters were not reported) the function is returned with the value "NR"

```
Else
        lbMMBtu = "NR"
        End If
End Function
```

2. <u>Module Handling the use of non-detected values</u>

2.1 Declaring the function that will return the values to the query. The parameters x and y refer respectively to concentration and detection limit.

```
Function Correction (x, y)
```

2.2 Identifying the concentration. If it is not reported, return the value "NR;" if it is not detected, take the value of the detection limit as the value for the concentration to be returned. Otherwise leave the value as it is.

```
If (x = "NR") Then
    Correction = "NR"
ElseIf
If  (x = "ND") Then
        Correction = y
Else
        Correction = x
End If

End Function
```

APPENDIX D

MACT Floor Rationale for Existing Turbines

Available Information – Inventory

- EPA inventory database has data on approximately 5,300 non-standby turbines.
- Approximately 8,000 turbines in U.S.
- EPA database contains varying information on 65% of the U.S. population.
- The data do not reveal controls specifically added to control HAPs.
- The database makes no reference to good operating practices.
- Database is representative

Available Information – Emissions Database

- 70 tests included in 46 source test reports.
  - Largely California air toxics hot spots data (AB2588).
  - Same tests run today would cost several million dollars including preparatory coordination and engineering analysis.
- Evaluated source test reports for accuracy and completeness prior to entering them into the emissions database.
- Data representative of turbine population.

Analysis of Emissions Database

- Examined:
  - Size
  - Load conditions
  - Fuel type
  - Operating & maintenance practices
  - Combustor design

- No correlation with HAP emissions could be drawn except for operation at partial load.

- No indication any of the data spread was the result of poor or improper operating practices or maintenance.

- Turbine operation substantially not operator adjustable.

- Turbine designer/manufacturer establishes combustion parameters.

- High speed precision turbomachinery – highly automated.

- Existing federal programs/permits require following manufacturer's recommendations.

Conclusions

- No relationship between HAP emissions and variables could be identified except for operation at partial load.

- Operating at partial load appears to increase HAP emissions, however operating at partial load is necessary for load following applications.

- There are no practical operating practices that can be found that will reduce HAP emissions.

- There are no data on emission reduction technologies or add-on control devices that are known to reduce HAP emissions in available information.

- The apparent difference in HAP emissions which may exist among combustion turbines is due to inherent variability among turbines and not to specific differences in "performance."

- Therefore, it is not possible to identify a subset of existing combustion turbines which represent the best performing 12%.

- There is no MACT floor for existing combustion turbines, because it is not possible to identify a "best performing" subset of turbines.

ATTACHMENT VI

INDUSTRIAL COMBUSTION COORDINATED RULEMAKING FEDERAL ADVISORY COMMITTEE

Combustion Turbines Emissions Testing

INTRODUCTION

The Industrial Combustion Coordinated Rulemaking (ICCR) Federal Advisory Committee (a.k.a. ICCR Coordinating Committee) recommends that the Environmental Protection Agency (EPA) test turbines representing the newest control technology in the industry (lean pre-mix, LPM) to provide emissions data for such units. Limited emissions data are available in the current turbine emissions database for combustion turbines using LPM technology. In addition, very limited data exist for add-on controls, i.e., CO oxidation catalysts. Sampling should take place before and after the CO oxidation catalyst to determine the effectiveness of the device in controlling the emission of HAPs. This information is necessary to determine the MACT floor for new sources, and above the floor options for new and existing sources. Recommendations for the specific pollutants to be tested are included for each fuel type. Some selected criteria pollutant emissions should be measured simultaneously with HAP emissions during testing in an effort to examine possible relationships between these pollutants to see if they can be used as HAP surrogates to reduce compliance monitoring costs and to determine if criteria controls contribute to HAP formation. The overall goal of the testing program is to assist the ICCR Coordinating Committee in making its recommendations to EPA by providing a more complete set of emissions data to develop MACT regulations. A secondary objective is to evaluate the effect of water or steam injection on HAP emissions. If a turbine selected for testing is equipped with water or steam controls, a run at the minimum load condition will be conducted with the water or steam on and off.

SOURCE DESCRIPTION

Process Description

The ICCR Coordinating Committee recommends testing five turbines: three natural gas-fired turbines and two distillate oil-fired turbines. The Committee believes that testing oil-fired turbines is a higher priority than testing gas-fired turbines and recommends testing oil-fired turbines first. Natural gas and distillate oil-fired turbines were selected since they represent the fuel used by the vast majority of turbines operating and being installed in the United States. The Committee recommends testing each turbine at various load conditions, within the range that the user can accommodate. The recommended loads should include, at a minimum, the maximum and minimum permitted or achievable load conditions.

Turbines with LPM combustion systems which are also equipped with CO oxidation catalysts should be sought for the natural gas-fired turbine tests. Units equipped in this manner are desired so that the ability of each technology to reduce HAP emissions can be tested on the same unit. LPM combustion systems are recommended because they represent the latest technology in the industry and the vast majority of new sources. In addition, LPM systems emit low levels of CO which may reflect low HAP emissions. CO oxidation catalysts are recommended since there is a strong perception that these catalysts will also reduce HAP emissions. Empirical data are required to confirm and evaluate their efficiency for the destruction of HAPs. If LPM units with CO catalysts are not available for the natural gas-fired turbine tests, the Committee recommends testing two LPM turbines with no add-on controls and one non-LPM turbine equipped with a CO catalyst.

For the distillate oil-fired turbines, the Committee recommends testing two turbines with CO oxidation catalysts.

The Committee recommends testing a cogeneration cycle turbine that is coupled to a duct burner.

The Committee recommends testing turbines of different sizes. One natural gas-fired turbine in each of the following ranges is recommended for testing: a) 1 to 10 MW; b) 15 to 50 MW; and c) above 70 MW. Two turbines, a 15-50 MW turbine and a >70 MW turbine, are recommended for the distillate oil-fired turbine tests.

Summaries of the recommended key turbine parameters and potential control information which should be documented in this testing program are presented in Table 1 and Table 2, respectively.

The specific pollutants recommended to be measured by fuel type are presented in Table 3. Emission stream measurements should be conducted at sampling points before and after the CO oxidation catalyst (when applicable) for all test runs. Pollutants indicated by an "*" in Table 3 should be measured using fuel sampling only at an appropriate point in the process stream.

Test Matrix

Table 4 provides the test matrix for the proposed turbine tests. This information should be monitored and recorded during testing on all units.

SAMPLING LOCATIONS

Sampling locations, whenever possible, should be selected in accordance to EPA Method 1 requirements. If sampling locations cannot be selected in accordance with Method 1 due to stack geometries and disturbances, the sampling locations should allow for the collection of the most representative concentration data for pollutants, O_2, and CO_2.

SAMPLING AND ANALYTICAL METHODS

The Committee may recommend sampling and analytical methods at a later time. A list of applicable test methods determined from the gathered test reports for combustion turbines is presented in Table 3.

The testing should will be expected to follow EPA QA/QC procedures and to recommend a chain of custody protocol for samples and requirements for test blanks in accordance with standard EPA protocols.

DETECTION LIMITS

The Committee recommends that the targeted detection limits (DLs) be less than or equal to the lowest detected values for those HAPs contained in the ICCR Combustion Turbines Emissions Database (version 2). These DL values for the HAPs to be tested are summarized in Table 5 under the column "Lowest Detected Value." In reviewing the test methods available, the Committee feels that manual sampling methods have DLs that can meet the above criteria. It may be possible to use FTIR, with a 100 meter pathlength, when the achievable DLs using FTIR are in the same range as the manual method DLs. FTIR will also be used to collect data on NOx, CO, CO_2, and, if appropriate, O_2.

Table 5 shows a comparison of manual method DLs to FTIR DLs for the HAPs included in the test plan, with the exception of biphenyl, phenol, styrene, and methanol. Information on these four pollutants is not available in the emissions database. However, these pollutants can be measured by the same sampling methods used to measure some of the other HAPs selected for testing. Therefore, the detection limits obtained for the four HAPs not in the emissions database will be determined by the sampling time selected for the methods being used to quantify other HAPs.

COST AND SCHEDULE

The Committee may provide cost estimates to conduct the Combustion Turbines Test Plan at a later time and may also recommend a schedule for testing and for submitting final test reports.

Table 1. General Information

Facility Information	Name	
	Address	
	Test Operator	
	Technical Contact	
	Phone Number	
	Altitude	
Turbine Info	Make	
	Model	
	Combustion Technology (e.g., LPM)	
	Mfgrs. ISO Rating (MW)	
	Operating Cycle	
	Equipped with CEMs or PEMS? (Indicate NOx, CO, etc.)	
	Other Features (Duct burner?)	
Fuel Info	Fuel Type	
	Fuel Composition	
	Fuel Lower Heating Value (LHV) (BTU/dscf or BTU/gal)	

Table 2. Control Device General Information

CO Oxidation Catalyst Information	Manufacturer	
	Type of Catalyst	
	Age (hrs)*	
	Catalyst space velocity	
	Catalyst face velocity	
	Space Volume (ft^3)	
	Other	
Other Features	Water or Steam injection?	
	Duct burner?	
	Duct burner make & model	
	Duct burner fuel type	
	Duct burner rating	
	Other	

* If multiple modules, indicate age of each.

Table 3. Pollutants to be Measured

Pollutants	Test Methods**	Natural Gas	Distillate Oil
Hazardous Air Pollutants (HAPs)			
2,2,4-Trimethylpentane	Method 18/TO-14	X	X
Acetaldehyde	FTIR/CARB 430/EPA TO-11	X	X
Acrolein	FTIR/CARB 430	X	X
Arsenic Compounds*	Fuel Analysis (ASTM D5185)	X	X
Benzene	Method 18/TO-14/CARB 410A	X	X
Beryllium Compounds*	Fuel Analysis (ASTM D5185)		X
Biphenyl	CARB 429 and 429 (m)	X	X
Cadmium Compounds*	Fuel Analysis (ASTM D5185)		X
Chromium Compounds*	Fuel Analysis (ASTM D5185)		X
Ethylbenzene	Method 18/TO-14/CARB 410A	X	X
Formaldehyde	FTIR/CARB 430/EPA TO-11	X	X
Hexane	Method 18/TO-14	X	X
Lead Compounds*	Fuel Analysis (ASTM D5185)		X
Manganese Compounds*	Fuel Analysis (ASTM D5185)		X
Mercury Compounds*	Fuel Analysis (ASTM D5185)	X	X
Methanol	Method 18/TO-14/Method 308	X	X
Naphthalene	CARB 429 and 429 (m)	X	X
Nickel Compounds*	Fuel Analysis (ASTM D5185)		X
PAH	CARB 429 and 429 (m)	X	X
Phenol	CARB 429 and 429 (m)	X	X
Styrene	Method 18/TO-14	X	X
Toluene	Method 18/TO-14/CARB 410A	X	X
Xylene (total)	Method 18/TO-14/CARB 410A	X	X
Criteria Pollutants			
Carbon monoxide (CO)	EPA Method 10/FTIR	X	X
Oxides of nitrogen (NOx)	EPA Method 7E/FTIR	X	X
Particulate Matter (PM)	Method 5		X

Total Hydrocarbons (THC)	Method 25A	X	X

*To be measured using fuel sampling only

**These are the test methods that have been recommended or that have been used to obtain emissions data on these pollutants.

TABLE 4. Test Matrix - Sample for Natural Gas

Turbine Make & Model:
Combustion Technology: Lean pre-mix (LPM)
Fuel Type: Natural Gas
Control Device: CO Oxidation Catalyst
Pollutants to be Measured: 2,2,4-Trimethylpentane, Acetaldehyde, Acrolein, Arsenic Compounds*, Benzene, Biphenyl, Ethylbenzene, Formaldehyde, Hexane, Mercury Compounds*, Methanol, Naphthalene, PAH, Phenol, Styrene, Toluene, Xylene, Carbon Monoxide (CO), oxides of nitrogen (NOx), and total hydrocarbons (THC)
Test Methods: Method 18/TO-14 (2,2,4-Trimethylpentane, Benzene, Toluene, Ethylbenzene, Xylenes, Hexane, Styrene); FTIR (Formaldehyde, Acetaldehyde, Acrolein, NOx, CO); CARB 429 and 429(m) (Biphenyl, Naphthalene, PAH, Phenol); Method 25A (THC); Method 5 (PM); Fuel Testing for metals (ASTM D5185)
Sampling Locations: Before and after the catalyst
Sample run time: 30 minutes, at a minimum

Run #:	1	2	3	4	5	6
Operating Conditions						
Load (MW)	MW1	MW1	MW1	MW2	MW2	MW2
Compressor Discharge Pressure (CDP) (psig)						
Turbine Inlet Temp (F)						
Fuel Flow Rate (gpm, scfm, etc.)						
Output**						
Other						
Control Device Information						
CO Catalyst Inlet Temperature (F)						
Water or steam injection rate (gpm, lb/hr, etc)						
Exhaust Gas Infomation						
Exhaust Gas Temp (F)						
Moisture content (%) ***						
O_2 content (%), avg. ***						
CO_2 content (%), avg. ***						
Ambient Conditions						
Temperature (F)						
Relative Humidity (%)						
Barometric Pressure (psig)						

* To be measured using fuel sampling only
** In applicable format (MW, steam or compressor pressure differential, output shaft hp, etc.)
*** Separate logs should be used by the testing contractor to record these data during the test runs

Table 5. FTIR Detection Limits vs. Detected Values from Emissions Database for Natural Gas

Pollutant	Units	Lowest Detected Value (average of sampling runs)	FTIR Detection Limit (100m pathlength)	
			Unconditioned	Conditioned
2,2,4-Trimethylpentane	ppb	2.57		
Acetaldehyde	ppb	3.14	50	10
Acrolein	ppb	1.37	25	2
Arsenic	µg/dscm	0.03		
Benzene	ppb	0.31	20	8
Biphenyl	ppb			
Ethylbenzene	ppb	4.87	8	
Formaldehyde	ppb	2.77	15	
Mercury	µg/dscm	0.26		
Methanol	ppb		10	2
n-Hexane	ppb	51.3		
Naphthalene	ppb	0.05	20	
PAHs	µg/dscm	0.07		
Phenol	ppb		50	5
Styrene	ppb		50	7
Toluene	ppb	4.43	40	5
Xylenes	ppb	1.38	30	5

APPENDIX A

COMBUSTION TURBINES TESTING PROTOCOL

- Recommendations:
  - Test only turbines with controls/potential to reduce HAPs
  - Test lean premix (LPM) - newest industry control technology/provide HAP emissions data
  - Test CO catalyst/HAP removal efficiency
- Need information to determine MACT options above the floor for existing turbines and determine MACT floor for new turbines
- Specific pollutants determined earlier
- Measure selected criteria pollutants/determine feasibility as surrogates
- Goals:
  - Provide more complete emissions data
  - Evaluate HAP emissions vs load and fuel type

COMBUSTION TURBINES TESTING PROTOCOL

! Recommendations:

- # Test 3 natural gas-fired and 2 distillate-fired turbines - the vast majority of U.S. turbines fire these two fuels
- # Test different sizes: 1-10 MW, 15-50 MW, AND >70MW for natural gas; and 15-50 MW AND >70 MW for distillate fuel
- # Seek distillate units with CO catalyst; test first
- # Seek 2 natural gas-fired units with LPM, 1 unit with CO catalyst*
- # Vary load - minimum and maximum permitted, achievable
- # One test to include a cogeneration unit with a duct burner
- # Recommended test budget estimated at $350,000 (based on testing 5 turbines)

*Unless find unit with both or test data from unit with LPM

COMBUSTION TURBINES TESTING PROTOCOL

- Follow EPA QA/QC procedures

- Recommend chain of custody protocol; meet standard EPA protocols

- Determine schedule for testing/report submittal

- Recommend detection limits (DLs) of those HAPs selected for testing be less than or equal to the lowest detected values for these HAPs contained in the emission database.